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PRE-ENGINEERING ASSESSMENT

OF

AN ENERSOLVE DEMONSTRATION PROJECT

AT

CENTRAL HEAT DISTRIBUTION LTD.

VANCOUVER, B.C.

FOR

DEPARTMENT OF ENERGY, MINES AND RESOURCES

CANMET, ENERGY RESEARCH LABORATORIES

OTTAWA, ONTARIO

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1.0 EXECUTIVE SUMMARIES

1.1 EXECUTIVE SUMMARY (ENGLISH)

Central Heat Distribution Limited, Vancouver, B.C., is a privately owned district heating company, regulated by the Province of British Columbia. Since 1968, one central plant, now of some 600,000 lbs/hr steaming capacity supplies one hundred major downtown buildings, through five miles of distribution piping, in the Vancouver core area with steam for heating, cooling and process loads.

Natural gas is the primary fuel with oil standby.

The work performed in this study is comprised of combustion efficiency tests on the boilers and the considered application of individual oxygen and combustibles trim equipment to each.

Load allocation control for boiler selection - optimization is included together with consideration of the application of economizers or air heaters to two of the five boilers that are not presently so equipped.

The results of testing indicate that oxygen and combustibles trim and load allocation control should be added to all boilers together with economizers at two boilers which are not so equipped at this time.

The total annual fuel savings for these additions is estimated at $160,500/year for a capital estimate of $344,000.

The simple payback period overall is 2.14 years.

Based on the encroaching obsolescence of equipment, other recommendations advise the timely upgrading of safety controls and the development of a distributed network combustion control system to a full electronic status.

There is, however, no tangible payback to this last step in terms of fuel savings, that has not already been accommodated in the primary recommendations.

Some moderate repairs are indicated to burner fan linkages and dampers and furnace gas by passing of boiler passes, to reduce the combustibles evident in the outlet of Boilers #1 and #2. This is a maintenance cost.

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1.2 SOMMAIRE ADMINISTRATIF

Central Heat Distribution Ltd., Vancouver, B.C., est une compagnie privée de chauffage de district. Depuis 1968, une installation centrale, d'une puissance actuelle de 600,000 lbs/hr, fournit de la vapeur à une centaine de bâtiments importants dans le centre-ville. La vapeur, utilisée pour le chauffage, refroidissement et des procédés industriels, est distribuée per un réseau de tuyauterie de 5 miles.

Le gas naturel est le combustible principal, avec le mazout comme combustibles de réserve.

Le travail accompli dans cette étude comprend des tests d'efficacité de combustion des chaudières, et une discussion sur l'utilisation d'équipement de réglage individuel de combustion et d'amenée d'oxygène.

Un contrôle d'allocation de charge, pour une sélection d'éfficacité optimale des chaudières est inclu, ainsi qu'une discussion de l'application d'économiseurs et de chauffe-air pour les deux chaudières qui n'en sont pas équipées.

Le résultat des tests indique que des équipements individuels de réglage d'oxygène et de combustion, ainsi qu'un contrôle d'allocation de charge, devraient être ajoutés à toutes les chaudières, en même temps qu'un économiseur aux deux chaudières qui n'en ont pas encore.

L'économie annuelle en combustible est estimée à $160,000/an, pour un investissement en capital de $344,000.

Le période de remboursement simple est de 2.14 années.

Vu que tout équipement devient rapidement suranné, il serait recommandé de remplacer graduellement les contrôles de sécurité par de l'équipement électronique, ainsi que de dévelloper un réseau de contrôle de combustion entièrement électronique.

Il n'y a pas de remboursement tangible pour ce dernier point, au point de vue économie de combustible, que n'aie pas déjà été considéré dans les recommandations primaires.

Quelques réparations mineures sont indiquées aux connections de ventilateurs de brûleurs, registres et veilleuses de gas de chaudière, pour réduire la quantité de combustible en évidence à la sortie des chaudières #1 et #2. Ceci est un coût d'entretien.

2.0 INTRODUCTION

2.1 General Description of Facility

Central Heat Distribution Ltd. is a district heating company located in downtown Vancouver, B.C., conceived in 1967, built in 1968 and has reliably served downtown Vancouver since that time in the business of the sale and distribution of high pressure steam for heating, cooling and process uses.

It is a privately owned utility company regulated by the British Columbia Department of Energy, Mines and Petroleum Resources, in much the same way as the B.C. Hydro facility is regulated by the same body in the distribution and sale of natural gas and electric power to British Columbia consumers in general.

The installed generating capacity of the C.H.D.L. steam plant is in the order of 610,000 lbs/hr of steam at a minimum distribution pressure of 185 psig.

The distribution sysetm currently extends for a total distance of 5 miles of buried steam piping.

Condensate is not generally returned to the plant.

Primary fuel is natural gas, with a standby fuel of #5 oil, normally used in the month of January, if the natural gas supply is curtailed.

2.2 Tests

Combustion tests were carried out using natural gas as a fuel. The efficiency results from these tests being derived from the methods outlined in the 'Combustion Handbook for Canadian Fuel Vol. 2/Gaseous Fuels as published by Energy, Mines and Resources Canada.

Since oil is little used except on a standby basis, combustion tests with oil fuels were not justifiable either on a test cost, or operational savings basis.

In British Columbia, there is a known variance in the energy content of natural gas and this has been considered in the potential application of improved combustion controls as a source of energy cost savings.

In the course of testing, some boiler problems were discovered in the area of burner register linkage control and the short circuiting of furnace gases resulting in incorrect combustibles content in the flue gas outlets.

C.H.D.L. uses a recently purchased portable O_2 combustibles analyzer*. They are not yet totally familiar with its potential.

The application of load allocation control to utilize the most efficient units for current optimal loading has been investigated together with the effect of oxygen and combustibles trim control.

The application of air heaters and economisers to some boilers has been considered and recommendations are included.

* Kane-May, Model 9101

2.2 Tests (Cont'd)

The conclusions and recommendations which follow deal with the effective results of the tests and the estimated application of appropriate cost effective modifications to the plant and/or individual boilers.

A description of the plant and its general mode of operation is included together with recorded data relating to annual operating loads and fuel costs on a comparative annual basis over a five year period. The test results are set out in a separate section of this report as are the expected efficiency improvements with related retrofit costs and payback terms.

In addition estimated costs are included for detailed engineering services for modifications; a retrofit of equipment and commissioning with owner acceptance; and a nine month monitoring and maintenance of the upgraded facility.

The established Statement of Work is included as Appendix A to this report, with Appendix B as the interpreted Scope of Work.

3.0 CONCLUSIONS AND RECOMMENDATIONS

3.1 We recommend that O_2 combustibles trim plus load allocation control at all units (clauses 6.8b and 6.8c) as proposed herein in the sum of $172,000 be implemented in view of the fuel savings which are conservatively estimated at $67,500/year (1.5% of the projected 1984 annual fuel bill of $4,500,000). In addition, this equipment modification will considerably improve operational safety by avoiding the potentially continuous operation with combustibles in the flue gas due to wide BTU variations while firing with natural gas.

Simple payback 2.55 years.

3.2 We recommend the application of an economiser at #1 boiler for the estimated sum of $90,000 with annual fuel savings of $52,000 per year based on 4 months continuous operation each year for a simple payback period of 1.75 years.

Similarily at No. 5 boiler an economiser application at an estimated cost of $82,000 should save $41,000 over a 4 month continuous operation each year for a simple payback of 2 years.

3.3 Total annual fuel savings for 3.1 and 3.2 above are estimated at $160,500/year for a total outlay of $344,000. A simple overall payback of 2.14 years.

	Clause 3.1	Clause 3.2	Sub Totals
3.4 a) Estimated detailed engineering costs for the implementation of the recommended modifications.	$ 20,000	$ 15,600	$ 35,600

3.4 b) Estimated contract retrofit costs based on the prepared engineering details of the recommended modifications.	$152,500	$156,400	$308,900
c) Estimated costs of a nine month monitoring and maintenance of the upgraded facility.			
Monitor	$ 12,000	$ 3,000	
Maintenance	3,000	3,000	
	$ 15,000	6,000	$ 21,000
Total			$365,500

3.5 There are existing problems at Boilers No. 1 and 2, with burner register linkage control and furnace gases by passing the furnace to the boiler outlet, causing the presence of high combustibles content in the stack gases.

These should and can be remedied with operational benefit to C.H.D.L.

3.6 The present metered fuel flow-airflow control system cannot compensate for the variable BTU content of the natural gas supply (up to 10% variation has been recorded).

The addition of O_2/combustibles trim (See 3.1) will remedy this situation.

3.7 Predicted costs versus efficiency gains are summarized under Clause 6.2 herein.

3.8 When funds are available it is recommended that solid state micro processor based burner safety systems (estimated cost $203,000) be provided to replace all existing semi-automatic relay systems which are approaching obsolesence and to be fully compatible with a new distributed network combustion control system for all units at an additional estimated cost of $399,000.

4.0 PLANT DESCRIPTION

4.1 Location

The Central Heat Distribution Ltd. district heating plant facility is located at 720, Beatty Street, Vancouver, B.C. - a downtown location and immediately adjacent to the currently developing Expo 86 World's Fair site and the B.C. Place downtown development area (20 year plan).

4.2 Service Area

The main steam distribution system at this time extends entirely to the west of the plant as far as Burrard Street, south to St. Paul's Hospital and north to Gastown with a total distribution network of some 5 miles, all served from one plant.

4.3 System Capacity

The 20" diameter main steam service leaving the plant west along Georgia Street has an ultimate capacity in excess of 500,000 lbs/hr at 185 psig.

4.4 Boiler Plant Equipment Status

a) The CHDL plant contains five packaged water tube boilers.

Unit No.	Year	Quantity	Manufacturer	lbs/HR Manuf. Capacity	Actual Capacity	A/H or Econ.
A/H = Air Heater. Econ = Economiser.						
1 & 2	1968	2	FWLTD	100,000		#1 Nil #2 A/H
3	1970-1	1	B & WLTD	135,000		A/H
4	1972-3	1	B & WLTD	200,000		Econ.
5	1983	1	C-B	75,000		Nil

b) Boilers #1, 3 and 4 have steam turbine driven F.D. fans. #4 has a 50% motor drive on the same shaft. Boilers #2 and 5 have motor driven F.D. fans.

c) Operating Conditions

Drum pressure 230/psig, dry and saturated. Feed water temperature 230°F nominal.

d) Fuels

Interruptible natural gas with #5 oil standby. Use of oil is minimal and restricted to gas interruption.

e) Fuel Costs

Currently, at $3,926,557 for 1983. Projected at $4,500,000 for 1984.

f) Combustion Controls

Primarily Bailey pneumatic circa 1968 thru 1973 with cross limiting metered fuels, and #5 boiler has Cleaver-Brooks 1983 controls, electric combined with jack-shaft. No metering or cross limiting.

The above applies to gas and oil firing.

g) O_2 Analyzers

A portable O_2 combustibles analyser is used for checking combustion conditions. One common O_2 analyzer is time shared on boilers 1, 2, 3, 4.

h) Constraints

Because of lower fuel efficiency, Boiler #1 is maintained largely as a standby unit i.e. no economizer or air heater and electric drive fan. There is some pulsation effect in #1 boiler.

i) Boiler #2

Boiler #2 is operated when high load conditions can be maintained. This is primarily because the turbine drive F.D. fan consumes a large amount of steam. The exhaust steam quantity from the turbine cannot be absorbed in the plant at low boiler loads.

j) Boilers #1 and #2 are both equipped with Coen packaged burners (1968) with opposed blade burner dampers. There is difficulty on account of wear, in making correct adjustments to achieve correct fuel-air ratios at all loads. As a result combustibles are evident in the flue gas from both boilers at high loads.

Both No. 1 and 2 boilers are serviceable as required.

k) Boilers #3 and #4 operate at good efficiency with suitable loading.

l) Boiler #5 is not yet in satisfactory service. The vendor is making adjustments and repairs to achieve guaranteed performance.

This is essentially a summer load and/or a standby unit to be used generally at or near full rating of 75,000 lbs/hr.

4.5 Plant Auxiliaries

a) Deaerators

The plant has two deaerators (both are "low headroom" types).
#1 (1968) capacity 250,000 lbs/hr.
#2 (1972) capacity 450,000 lbs/hr.

b) Feed Piping

Feed piping arrangements are such that either dearator can be connected to any feed pump.

c) Feed Pumps

There are a total of six feed pumps with turbine or motor drives to suit plant load and exhaust steam conditions.

d) Condensate Returns

Condensate returns are minimal say 15%.

The reason for the lack of condensate returns relates to the originally installed condensate system which utilized fibreglass pipe.

The pipe material was unsuitable for the service being of layered wrap construction with a temperature limit of 240°F. Provisions for pipe expansion were inadequate.

The line failed in numerous locations from the effect of the excessive temperature of leaking steam traps and line fractures, from expansion forces.

Attempts were made initially to internally line the fibreglass with thin wall stainless tubing. This technique was partly successful but could not be universally employed. In general it was uneconomical to replace the lines through the downtown streets.

The company policy therefore derived from this experience and other experiences entailing the failure of carbon steel condensate lines (external corrosion), is now that condensate return lines shall not be installed.

If it were a matter of a one time initial capital investment it would be economically acceptable to install the lines but experience has shown that with the methods originally used for this installation there is no economic replacement solution.

The development of a new large distribution area close to the plant, e.g. B.C. Place could however, encourage reconsideration of the use of condensate return piping with adequate materials and design installation techniques. This remains to be considered.

In such an event we would expect a minimum energy saving of approximately 100 BTU/lb of steam generated at 230 psig (1200 BTU/lb), or say 8%, ($360,000/year of 1984 fuel cost) to be offset also against line capital, operating and maintenance-replacement costs.

e) <u>City Water Make Up</u>

City water make up averages 85%. C.H.D.L. does not install condensate return systems as a matter of policy but gives all possible assistance to customers to utilize the maximum amount of sensible heat in condensate before pumping to sewer.

f) <u>Water and Chemical Treatment Costs</u>

Water quality is good in Vancouver and minimal water treatment is required. Costs are reasonable for this type of operation.

4.6 Standby Power Systems

The plant is equipped with a 250 kw diesel generator which takes up to 5 minutes for a compressed air start to full line voltage under load.

For the maintenance of combustion and flame failure functions, the individual boilers are equipped with:

#1 and #5 units - no standby.

#3 and #4 units - a 2 kva turbo-generator. B.C.Hydro is a backup to this unit.

#2 unit - battery operated invertor backup.

#2, 3, 4 boilers - FD fans are steam turbine operated as are also an adequate number of boiler feed pumps.

4.7 Existing Boilers - Combustion Control Systems

a) Boiler #1 and 2

Both units are similar and are equipped with "Coen" package burner systems which are similar to the Bailey pneumatic system detailed below for boilers 3 and 4 but without fuel metering on oil firing.

b) Boiler #3

Boiler #3 is equipped with a system of Bailey air operated automatic combustion control equipment for oil and gas firing; fuels to be burned individually but never in combination. Equipment designed to control fuel flow and forced draft air in parallel, the impulse being received from a master pressure controller with

4.7 b) Boiler #3 (Cont'd)

readjustment to the fuel flow from the fuel flow/air flow ratio controller to maintain optimum excess air at all loads.

Recorders: Steam Flow
Gas Flow
Oil Flow
Air Flow
Drum Level
Air Heater Temperatures

2 - Element feed water control. Single F.D. combination burner operation, B & W multi-spud type, for gas and a steam atomising oil burner.

4.7 c) Boiler #4

Boiler #4 is equipped with a set of combustion control, feedwater and instrumentation components which provide close loop feedback control with cross limiting from metered oil, gas and air and two element feedwater control. System receives primary signal from existing plant master.

Flow Tie-Back Combustion Control

The Bailey pneumatic operated flow tie-back combustion control system provides fuel flow and air control from an index of steam load. Demands for fuel and air from an index of load compared with measured fuel flow and air flow and proportional plus integral control action ensures that measured flow equals demand.

4.7 c) Boiler #4 (Cont'd)

A set of limits are superimposed on the combustion control system to ensure that there will always be air present to burn the fuel. On a boiler load increase, air flow leads fuel flow, and on a boiler load decrease, air flow lags fuel flow. If either air or fuel is unable to respond properly, the other control loop is limited to a safe condition. This system provides metered fuel flow and air flow in the correct ratio for optimum boiler efficiency over the entire turndown range of the burners.

Recorders: Steam Flow
Gas Flow
Oil Flow
Air Flow
Drum Level
Economiser Temperatures

4.7 d) Economiser: Flue gas in/out - Temperatures - 587/375°F
Economiser: Feed water in/out - Temperatures - 220/282°F

2 element feed water control.

2 - F.D. combination burners B & W parallel throat, multi spud type for gas and steam atomising oil burners.

4.7 e) Boiler #5

Boiler #5 is equipped with a system of Cleaver-Brooks electric positioning controls (a jackshaft system) full modulation through potentiometer type positioning controls for fuel and air.

Recorders: Steam Flow, Drum Level

4.7 e) Boiler #5 (Cont'd)

1 - Two element feed water control, F.D. burner operation, 'CB' jet type low pressure gas/air atomising oil burner

4.7 f) Flame Failure Systems

Flame Failure Systems are generally ECA "Fireye" relay logic, semi-automatic systems typical of the period when the boilers were supplied.

4.7 g) Operating Criteria

No. 2 boiler is used at high loadings only because of the plant inability to absorb the exhaust steam from the turbine driven F.D. fan under other conditions.

Plant operates at about 85% make up conditions i.e. - low condensate returns.

No. 3 and No. 4 boilers are the most efficient units and suit the plant loading requirements.

No. 3 and No. 4 F.D. fans are turbine driven. No. 4 has an auxillary electric motor drive (50%) on the same shaft for start up.

No. 5 boiler is a summer base load unit (100%) only and will not normally operate on oil firing at anytime.

No. 1 boiler is currently rated as a standby unit since it is not equipped with heat recovery devices and has a motor driven F.D. fan.

4.8 Plant Operational Data

To furnish the necessary and appropriate background for an understanding of the plant system operations various load and energy data are included in this section of the report.

The predominant load for the central plant is made up from the heating loads for approximately one hundred major buildings and line losses.

Air conditioning (absorption) is a minor summer time load component.

4.8 a) Load - Time Characteristics

Two charts are attached, sketches 4.8-1 and 4.8-2, which have been developed from the recorded fuel consumption, steam generation and metered sales to customers over a 5 year period. Examination indicates a traditional generation pattern paralleling the degree day conditions.

Some summer steam is used for absorption air conditioning. Distribution losses are constant through the year without regard to load change.

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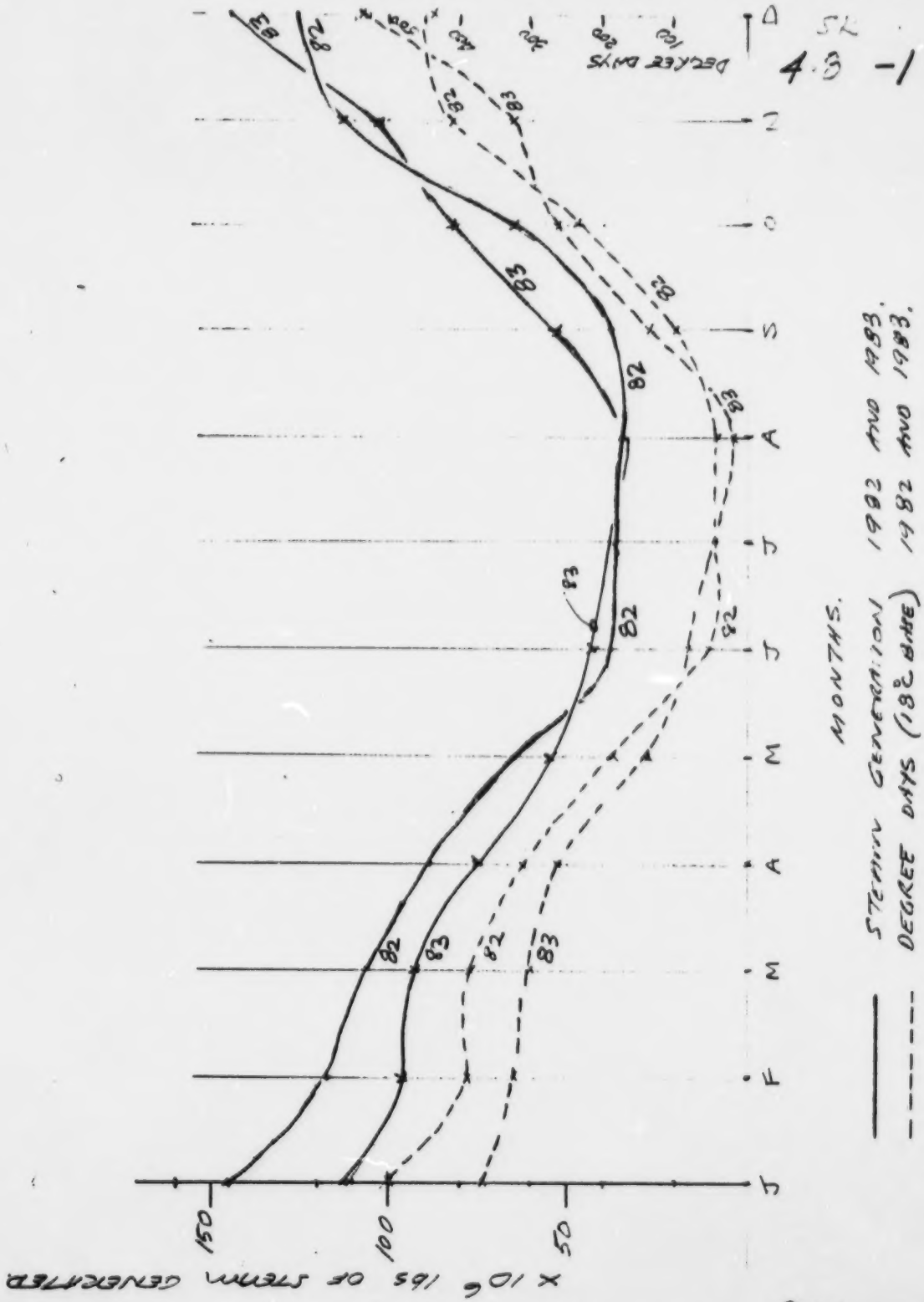

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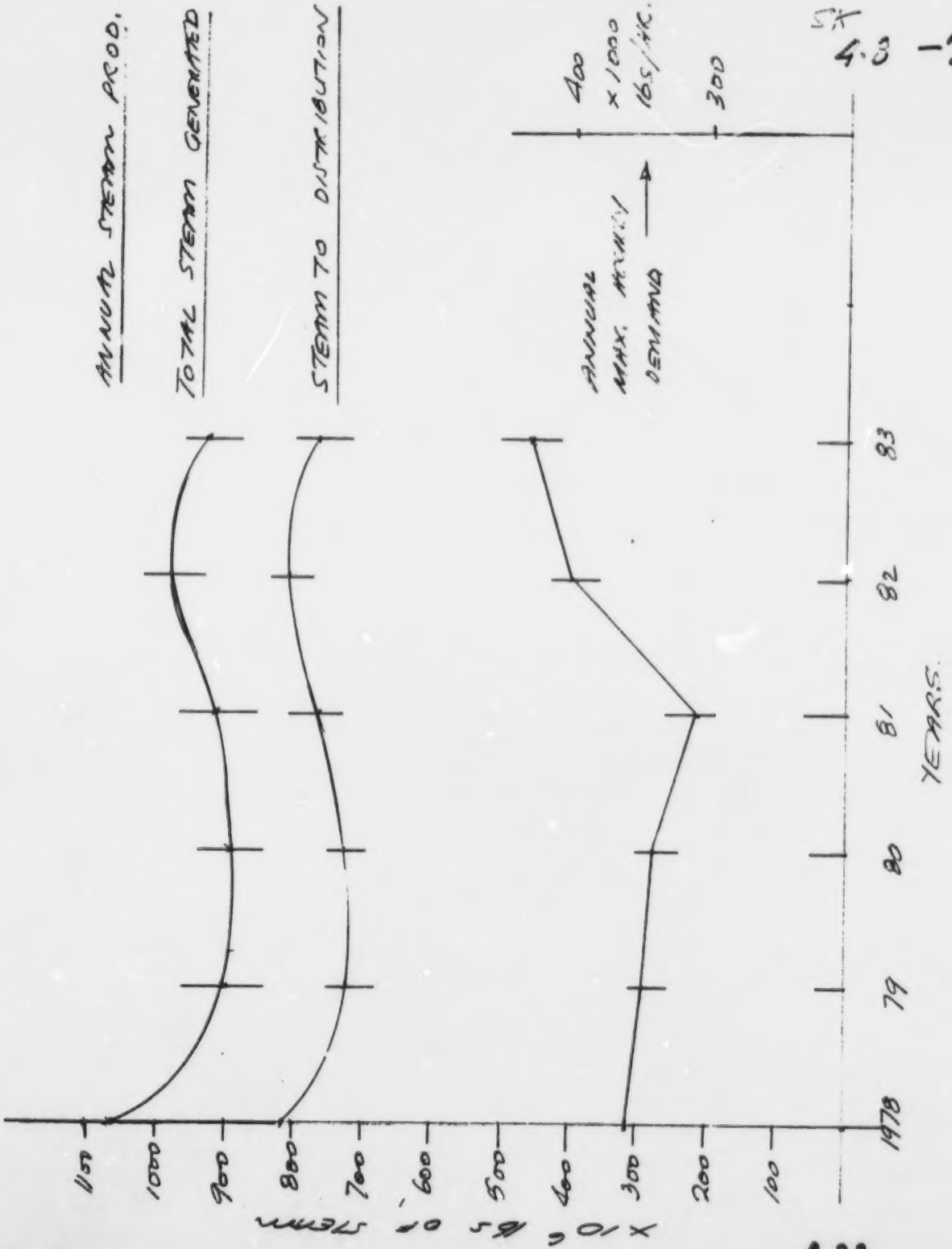


4.8 b)

CHDL - ENERGY USE DATA

Year	1983	1982	1981	1980	1979	1978
Item						
Fuel Used - Therms Fuel Used - GJ	10,743,228 1,113,410	11,161,373 1,177,525	10,695,203 1,128,344	10,389,736 1,096,117	10,494,603 1,108,181	11,367,315 1,199,252
Steam Gen. - lbs - kg	928.168×10^6 421.017×10^6	978.374×10^6 443.790×10^6	921.234×10^6 417.872×10^6	897.075×10^6 406.913×10^6	898.766×10^6 407.680×10^6	$1,063.973 \times 10^6$ 482.618×10^6
Steam Sold - lbs - kg	652.184×10^6 295.830×10^6	692.346×10^6 314.048×10^6	652.067×10^6 295.778×10^6	625.355×10^6 283.661×10^6	623.060×10^6 282.620×10^6	713.596×10^6 323.687×10^6
Degree Days	2,085	3,098	2,823	3,058	2,939	2,951
Max. Hourly - lbs - kg	426,000 192,234	396,000 179,626	308,000 139,709	339,000 153,770	349,000 158,306	355,000 161,028
Average Hourly - lbs - kg	165,000 74,844	173,000 78,473	162,000 73,483	213,500 96,844	213,000 96,617	166,628 75,583
Oil / Gas Energy %	3.34%	2.22%	0.8%	11.7%	15.5%	11.8%
Energy Sold / Energy Purchased %	60.7%	61.86%	60.97%	60.2%	59.4%	62.8%

4.8 b)

CHDL - ENERGY USE DATA

Year	1983	1982	1981	1980	1979	1978
Item						
Gas Interruption HRS	100	-	33	543	718	603
Energy Cost $	3,926,557	3,740,935	2,530,729	1,842,248	1,544,928	1,727,754

Fuel Used is Gas & Oil Total

1 Therm = 100,000 BTU
1 GJ = 948,000 BTU
Therms x .1055 - GJ

4.8 c) 1983

C.H.D.L. Steam Generated Versus Degree Days

Month	Units	Steam Generated x 1000	Steam Sold x 1000	Degree Days
January	lbs	110,344	78,998	365
	kg	50,052	35,833	
February	lbs	95,262	68,819	325
	kg	43,211	31,216	
March	lbs	91,353	61,619	304
	kg	41,438	27,950	
April	lbs	76,754	59,810	262
	kg	34,816	27,130	
May	lbs	55,762	32,516	141
	kg	25,294	14,749	
June	lbs	41,590	24,856	83
	kg	18,865	11,275	
July	lbs	39,141	21,891	44
	kg	17,754	9,930	
August	lbs	35,521	21,947	18
	kg	16,112	9,955	
September	lbs	52,067	30,629	135
	kg	23,618	13,893	
October	lbs	81,388	54,559	265
	kg	36,916	24,748	
November	lbs	103,898	72,765	325
	kg	47,128	33,006	
December	lbs	145,088	123,775	538
	kg	65,812	56,144	
Year	lbs	928,168	652,184	2805
	kg	421,017	295,830	

Degree Days are based on 18°C tempeature.

4.8 c) 1982

C.H.D.L. Steam Generated Versus Degree Days

Month	Units	Steam Generated x 1000	Steam Sold x 1000	Degree Days
January	lbs	145,613	111,446	499
	kg	321,016	50,552	
February	lbs	118,626	92,338	387
	kg	53,809	41,885	
March	lbs	107,298	80,394	389
	kg	48,670	36,467	
April	lbs	88,747	61,468	309
	kg	40,256	27,882	
May	lbs	62,687	45,581	188
	kg	28,435	20,676	
June	lbs	38,878	21,759	52
	kg	17,635	9,870	
July	lbs	37,441	19,716	46
	kg	16,983	8,943	
August	lbs	35,674	20,839	45
	kg	16,182	9,453	
September	lbs	37,647	21,375	102
	kg	17,077	9,696	
October	lbs	66,152	45,775	242
	kg	30,006	20,764	
November	lbs	113,387	80,479	411
	kg	51,432	36,505	
December	lbs	126,224	91,176	431
	kg	57,255	41,357	
Year	lbs	978,374	692,346	3100
	kg	443,790	314,048	

Degree days are based on 18°C temperature.

4.8 d) Rapid Load Changes - Plant Safeguards

Rapid load changes are not a normal experience.

The rare known exception will be the roof snow melting demand from the B.C. Place Stadium (adjacent) which can vary from 10,000 to 90,000 lbs/hr rate in a few minutes (to heat up to 3×10^6 CFM of air which is pressured into the double inflated roof space).

The plant header pressure is safeguarded by an automatic valve which prevents decay of the plant pressure under rapid load change to a minimum of 180 psig.

5.0 TESTS AND RESULTS

5.1 Tests - Gas Firing and Oil Firing

A review of interruptible gas with #5 oil standby firing shows that the historical annual use of oil fuel at C.H.D.L. ranged from 0.8% to 15% of the thermal value of gas fuel used and depends on the relative costs of oil and gas, climatic variations and the gas supply position via B.C. Hydro and West Coast Transmission Co.

For the last 3 years the annual range of thermal utilization of oil fuel has been from 0.8% to 3% of total needs with corrsponding annual costs of 1.25% to 5% allowing for unit oil price increases.

Item	1983	1982	1981
Gas consumed GJ	1,095,537	1,151,338	1,119,327
#5 Oil consumed GJ	37,873	26,187	99,017
Gas Cost $	3,720,425	3,603,014	2,499,246
Oil Cost $	206,132	137,921	31,483
Energy % Oil / Oil & Gas	3.34	2.22	0.8
Cost % Oil / Oil & Gas	5.54	3.68	1.26
Assumed potential max. 1.5% savings of oil costs, $ amount annual payback-gas	55,806	54,045	37,489
-oil	2,061	1,379	315

On the basis of a potential 1.5% future saving in oil costs there is no case to establish a reasonable payback period for improvements in oil firing.

5.1 Oil firing tests were therefore considered to be inappropriate and would have involved C.H.D.L. in a pointless expenditure of $7000-8000 above current gas consumption costs for an oil firing test period.

With respect to appropriate upgrading proposals herein for gas firing, the effects that they will have will in any event apply to the oil firing mode.

Typical Oil Specification at C.H.D.L.

#5 oil

% Mass sulphur level 2.0% maximum
1.03% typical

Density at 15°C 0.9588 kg/l or 15.6° A.P.I. = 0.81% by weight.

Natural Gas Variations

The B.C. Hydro Natural Gas supply BTU content varies considerably (up to 10.5%). The tests were based on the developed data for Fuel 1007 Natural Gas in the Combustion Handbook for Canadian Fuels.

Appendix C contains recorded variations of the Natural Gas BTU content over two separate month periods. Variations are shown from 1004.8 to 1110.7 BTU/cu. ft.

5.2 Check Test of Fuel and Steam Metering Devices

On March 16, 1984 gas flow and steam flow meters on boilers #1, 2, 3 and 4 were checked and verified by Hank Weverink of Inproheat Industries Ltd. The report of their observations and actions is attached in Appendix E.

5.3 Furnace combustion tests firing natural gas were performed on Boilers #1 thru #4. Boiler #5 was not available for purposes.

The tests were performed making use of the methods and graphs provided in the Combustion Handbook for Canadian Fuels 1973 Vol.2 - Gaseous Fuels (Fredrick and Hayden) EM&R Canada, Appendix A, Sample Combustion and Heat Loss Calculations and charts for Fuel 1007 BTU/cu.ft. Natural Gas, Figures 1 thru 5 for the determination of combustion components.

The charts are included herein also under Appendix D.

5.4 The test recording data sheets for Boilers #1 thru 4 are included under Appendix D.

5.5 Test Results - Summary

Boiler No./ Test No.	Steam Flow	% O_2	Stack Temp	Air Temp	Dry F.G. Loss	Hyd. Loss	Eff'y Gain	Remarks
4 I	161,000	3.3	370°F	75°F	5.73%	11.10%		
	162,000	1.5	360°F	75°F	5.03%	11.05%	0.75%	Reliable results
4 II	93,000	3.4	312°F	75°F	4.65%	10.85%		
	94,000	1.5	307°F	75°F	4.10%	10.80%	0.55%	Reliable results
3 I	63,000	4.5	330°F	75°F	5.32%	10.92%		
	63,500	2.0	315°F	75°F	4.37%	10.85%	1.02%	Reliable results
3 II	109,000	3.3	360°F	75°F	5.54%	11.05%	0.75%	
	111,000	1.5	350°F	75°F	4.85%	11.00%		Reliable results
1 I	42,000	3.2	422°F	70°F	6.84%	11.40%		
	42,000	1.5	419°F	70°F	6.16%	11.35%	0.75%	Reasonable results
1 II	86,000	3.3	505°F	70°F	8.45%	11.70%		Excessive combustible if O_2 reduced
2 I	53,000	3.3	462°F	75°F	7.52%	11.50%		
	53,000	2.0	460°F	75°F	7.00%	11.48%	0.50%	Reasonable results
2 II	86,000	4.0	545°F	75°F				Excessive combustible if O_2 reduced

Summary of heat losses based on natural gas 1007 BTU content/cu. ft. derived from A Combustion Handbook for Canadian Fuels (1973), Volume 2 - Gaseous Fuels at 1007 BTU/cu. ft. Friedrich and Hayden. EMSR.

5.6 Refer to the Combustion Handbook for Canadian Fuels, Vo. 2, Appendix A, page 14 for the basis of the following heat loss calculations for Boilers #1 thru #4.

5.7 From A.3.1 - Dry Flue Gas Loss

Heat Loss Calculation
Boiler No. 1
April 24, 1984

Test I - @ 3.2% O_2 = 117% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 810 \times 0.24 \times 352 \times \frac{100}{10^6} = 6.84\%$$

- @ 1.5 O_2 = 107% T.A.

$$\text{Loss} = 736 \times 0.24 \times 349 \times \frac{100}{10^6} = 6.16\%$$

Test II - @ 3.3% O_2 = 117% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 810 \times 0.24 \times 435 \times \frac{100}{10^6} = 8.45\%$$

5.7 <u>From A.3.1</u> - Dry Flue Gas Loss

<u>Heat Loss Calculation</u>
<u>Boiler No. 2</u>
May 7, 1984

Test I - @ 3.3% O_2 = 117% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 810 \times 0.24 \times 387 \times \frac{100}{10^6} = 7.5\%$$

- @ 2.0% O_2 = 110% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 758 \times 0.24 \times 385 \times \frac{100}{10^6} = 7.0\%$$

Test II - @ 4.0% O_2 = 120% T.A.

Dry flue gas - 810 lbs/10^6 BTU

$$\text{Loss} = 832 \times 0.24 \times 470 \times \frac{100}{10^6} = 9.38\%$$

5.7 From A.3.1

Heat Loss Calculation
Boiler No. 3
April 24, 1984

Test I - @ 4.5% O_2 = 125% T.A.

Dry flue gas = 869 lbs/10^6 BTU

$$\text{Loss} = 869 \times 0.24 \times 255 \times \frac{100}{10^6} = 5.32\%$$

- @ 2.0% O_2 = 110% T.A.

Dry flue gas = 758 lbs/10^6 BTU

$$\text{Loss} = 758 \times 0.24 \times 240 \times \frac{100}{10^6} = 4.37\%$$

Test II - @ 3.3% O_2 = 117% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 810 \times 0.24 \times 285 \times \frac{100}{10^6} = 5.54\%$$

- @ 1.5% O_2 = 107% T.A.

Dry flue gas = 736 lbs/10^6 BTU

$$\text{Loss} = 736 \times 0.24 \times 275 \times \frac{100}{10^6} = 4.85\%$$

5.7 <u>From A.3.1</u> Dry Flue Gas Loss

<u>Heat Loss Calculation</u>
<u>Boiler #4</u>
April 18, 1984

Test I - @ 3.3% O_2 = 117% T.A.

Dry flue gas = 810 lbs/10^6 BTU

$$\text{Loss} = 810 \times 0.24 \times 295 \times \frac{100}{10^6} = 5.73\%$$

- @ 1.5% O_2 = 107% T.A.

Dry flue gas = 736 lbs/10^6 BTU

$$\text{Loss} = 736 \times 0.24 \times 285 \times \frac{100}{10^6} = 5.03\%$$

Test II - @ 3.4% O_2 = 118% T.A.

Dry flue gas = 817 lbs/10^6 BTU

$$\text{Loss} = 817 \times 0.24 \times 237 \times \frac{100}{10^6} = 4.65\%$$

- @ 1.5% O_2 = 107% T.A.

Dry flue gas = 736 lbs/10^6 BTU

$$\text{Loss} = 736 \times 0.24 \times 232 \times \frac{100}{10^6} = 4.10\%$$

6.0 EFFICIENCY IMPROVEMENTS

6.1 As a result of the testing it appears that efficiency gains should result on the various units in one or more of the following areas:

a) O_2/combustibles trim
b) Load allocation control
c) Economiser installations
d) Air heater installations
e) Future - distributed network combustion control system

6.2 Proposed Modifications

6.2.1 Summary of Proposed Modifications

Item; Add	Cost Est.	% Fuel Savings $ Ann. Savings	Simple Payback Years
a) O_2/combustibles trim control and alarm for 5 boilers (to pneumatic systems)	$ 96,350	0.75 $ 33,750	2.85
b) Alternate O_2 combustibles trim and configurable controller for 5 boilers, (new electronic system)	$147,500	0.75 $ 33,750	4.4

	Item; Add	Cost Est.	% Fuel Savings $ Ann. Savings	Simple Payback Years
c)	Load allocation control for 5 boilers, add to b) above only	$ 25,000	0.75 $ 33,750	0.74
	From above 'b + c'	$172,500	$ 67,500	2.55
d)	New distributed network control system, electronic transmitters and control room for 5 boilers (future)	$399,000		
e)	New solid state burner safety systems for 5 boilers	$203,000		
f)	Economizer at #1 Boiler	$ 90,000	4.00% $ 52,034/period	1.75
g)	Economizer at #5 Boiler	$ 82,000	4.1% $ 40,747/period	2 years
h)	Air heater at #1 Boiler	$125,000	4.26% $ 55,416/period	2.7
i)	Air heater at #5 Boiler	$116,000	5.05% $ 50,000/period	2.3

6.3 Constraints Affecting Efficiency Improvements

a) This plant delivers into a large heating system load which is quite stable and subject only to seasonal variations. Controls must, however, always be capable of responding to upset/trip conditions which could produce a load swing of 15-20%.

b) Steam is generated at 225 psig and delivered through main reducing valves at approximately 200 psig to the system. The system pressure cycles constantly ±5% for reasons not presently known. Since all boiler auxiliary drives are steam turbines this cycle is transmitted via steam header and turbine back pressure throughout the controls.

This has resulted in the compromising of control settings and also prevents close fuel/air ratio control.

c) In addition to the above and as a result of our testing, we have found that the gas btu content varies from 1125-1135 in the summer to 1020-1030 in the winter. There is no way that the present metered fuel flow-air flow system can compensate for this.

Given certain conditions, fuel losses can easily be at a constant 5%.

This arises in the following manner.

Normal burner/combustion control systems are set up for 10% excess air with gas firing.

This is established on a volumetric ratio of fuel and air and not on a ratio of gas BTU content to air volume.

10% excess air relates to about 2% O_2 i.e. an acknowledged safe margin limit. The average burner can not perform correctly with an infinite reduction of O_2 down to stoichiometric conditions.

There are physical and practical limitations. Therefore should the BTU per cubic foot value of the gas fuel increase by any percentage above that upon which the controls were set up, there is no means by which the burner control system can compensate for the available excess BTU value in the gas.

Hence with a known BTU variation of up to 10% per cubic foot of gas it is reasonable to indicate a fuel loss of 5% in the form of unburned fuel passing through the furnace to the boiler stack.

An extension of the above will be the application of a low excess air burner where minimym oxygen is a normal combustion condition. A larger BTU loss of unburned fuel can occur in these circumstances.

d) Tests on Boilers 1 & 2 while reasonable, indicated problems, which we understand from operating personnel, are to do with internal burner register linkage control or furnace gases partially short circuitng through leakage to the boiler outlet.

High load test on these two boilers, at the desired excess air amount of 10% were not possible due to combustibles resulting from the above.

Initial testing in these boilers (see combustion tests and air flow 1968) indicated no such problems and we feel that modest repairs would allow operations at desired excess air rates.

e) Boiler No. 5 was down for unscheduled repairs and not available for testing.

f) Owners have only recently purchased a portable O_2/combustibles analyzer and thus were unaware of some of the above problems.

6.4 Addition of Oxygen & Combustibles Trim (Sketch No. 6.4-1)

In order to realize savings found, it is obvious that individual analysers are required on each boiler. This is extremely important considering the variable gas BTU content.

Not so apparent is the effect of the systems cycle (6.3.6) in realizing good O_2 trim control. It is only through the use of new electronic control capabilities (6.7a) that we feel that maximum savings will be realized. Such controllers can be programmed to 'ignore' the cycle effect without degrading O_2 trim benefits.

6.5 Load Allocation Control (Sketch No. 6.5-1)

Predicated individual boiler effeciencies vary by approximately 4%. While total efficiency tests were not conducted, plant records confirm these figures.

6.5 A figure of only 0.75% has been used in savings calculated for incorporating load allocation to total steam generation.

6.6 Predicted Efficiency Gains

Oxygen trim control	0.75%
Load allocation control	0.75%
Total	1.5%

Annual fuel bill (1984) $4,500,000

Savings: 0.015 x 4,500,000 = $67,500 per year.

KEEN ENGINEERING CO. LTD.

PROJECT 23540.23440.3.9106-5 PROJECT NO. 6227-01

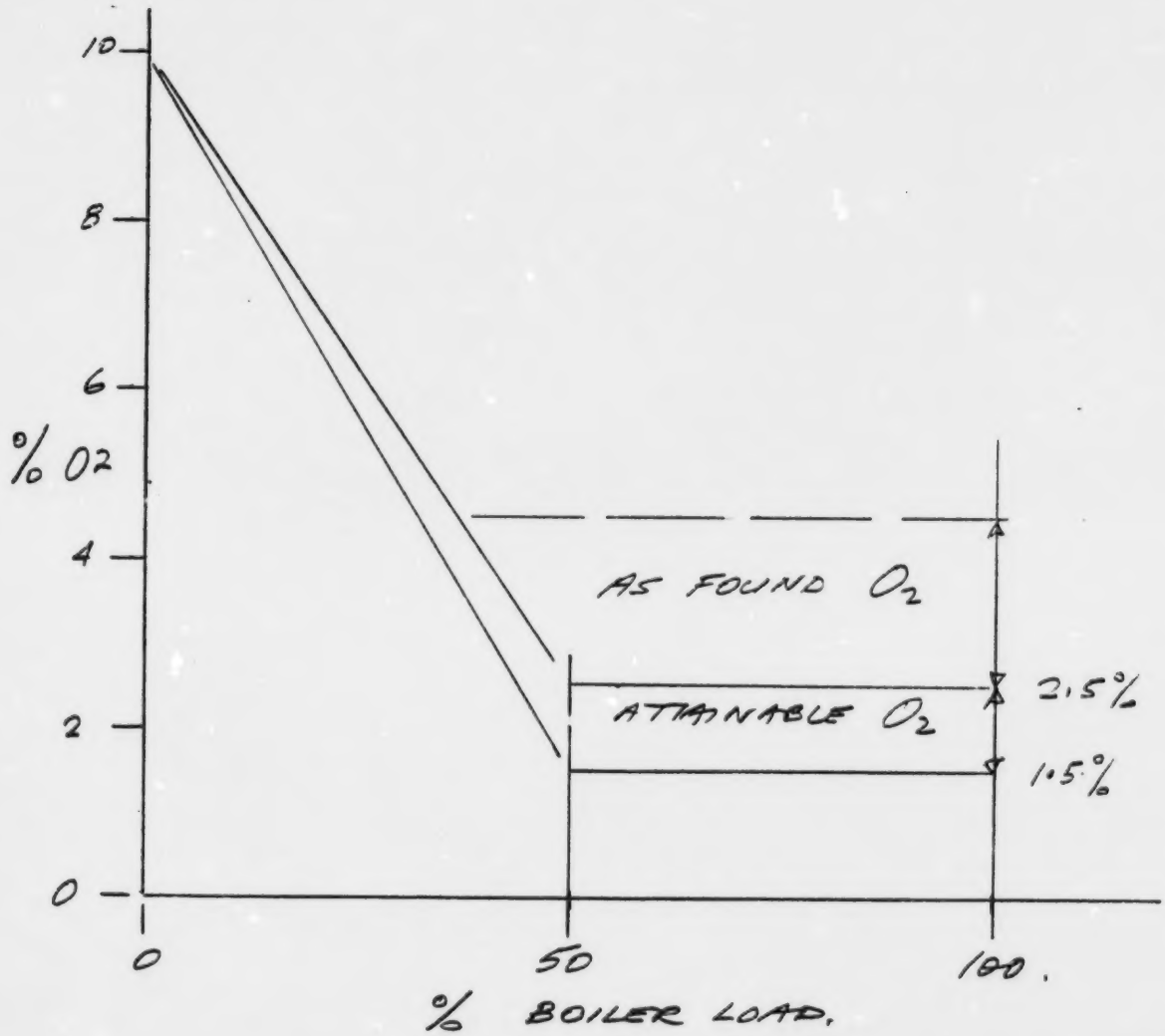
D.S.S. ENERSOLVE

C.H.D.L. DATE MAY 7 84

ALLOWABLE O_2 TARGET BY JG

CURVE

SK 6.4-1



6.7 Proposed Equipment Modifications

6.7 a) Phase I (refer to 6.8a)

The addition of minimum oxygen trim equipment tied into existing pneumatic controls is not recommended, for the following reasons:

a) The required additional controllers, if pneumatic, would have questionable ability to provide precise O_2 control over the desired ranges (see Sketch 6.4-1).

b) In order to effectively implement O_2 control, new controllers must be capable of providing decoupling features (see cycling constraints in 6.3b) to permit the attainment of efficiency improvements.

c) Pneumatic control does not permit the use of load allocation efficiency control which we estimate will provide approximately 50% of the fuel savings.

d) Pneumatic instruments and controls in industry are currently being phased out due to lack of market demands. Hence buying new pneumatic instruments and controls complicates future obsolescence problems.

6.7 b) Addition of O^2 and Combustibles Trim Control and Alarm (electronic)

We strongly recommended that this equipment be purchased. Such configurable controllers (similar to Fischer and Porter Chameleon line) provide the required capability of:

- dead band control techniques

6.7 b) Cont'd

- sample and hold principle
- excellent programmable control features for load efficiency calculations
- control decoupling

Implementation will provide for all of the immediate attainable efficiency increases through improved control strategies at approximately 1/3 of the cost of a total distributed system.

6.7 c) All Electronic Control System - Future

We recommend that the extra cost for a totally new all electronic control system be considered at a future date consistent with the obsolescence of existing systems becomming a major difficulty due to maintainance and spare parts supply problems.

The relatively stable and predictable load conditions in this plant negate the use of some of the existing control loops (fuel/air ratioing particulatily (i.e. absence of load swings) and permits optimum efficiency of operation through a more conventional parallel control supported by a good reliable O_2 combustibles trim package including combustibles trace analysis.

6.7 d) Safety Systems - Related Comment

While perhaps not considered within the scope of this project, we feel it necessary to document our concern that "current standard" safety systems bear equal consideration to efficiency enhancements. Often in the pursuit of economic gain, safety of operation, especially at constant minimum excess air conditions, is overlooked.

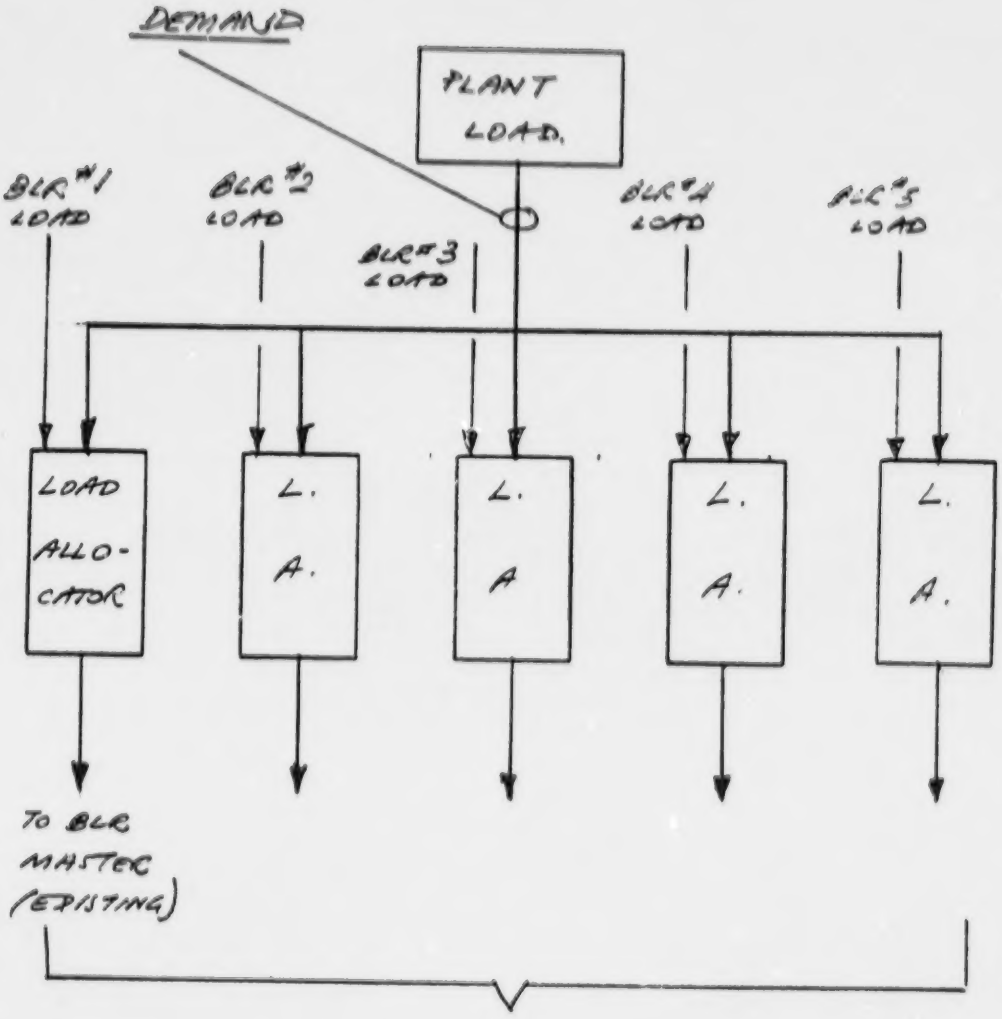
6.7 d) Cont'd

Experience has shown that relying solely on the safety system scanner to protect boilers on "flame failure conditions" is short sighted. When operating at minimum margins of fuel-air safety, we deem it essential to also consider the effects of partial loss of flame, etc. as defined by the N.F.P.A. committee on furnace explosions, as an integral requirement of total plant operation (i.e. fuel cut back to available combustion air).

ENGINEERING CO. LTD.

PROJECT 0352, 23440.3, 9106.5 PROJECT NO. 6227-01
D.S.S. ENERSOLVE
C.M.D.C. DATE MAY 7 1974
LOAD ALLOCATION CONTROL BY JG

SK 6.5-1



ALLOCATED DEMAND BY INDIVIDUAL BOILER EFFICIENCY.

6.8 Budget Costs of Proposed Changes

6.8 a) Phase I

Add basic O_2 trim control and combustibles trim and alarm to pneumatic systems (for 5 boilers).	$ 78,500
10% contingency	7,850
Installed	$ 86,350
Engineering Cost Estimate	
Office Design	$ 7,500
Field supervision	2,500
Keen	$ 10,000
Total Budget	$ 96,350

6.8 b) Phase II Alternate to Phase I Above

Add O_2 trim and combustibles trim and alarm control using new configurable Electronic Controller	$120,000
10% contingency	12,000
Installed	$132,500
Engineering Cost Estimate	
Office design	$ 12,000
Field supervision	3,000
Keen	$ 15,000
Total Budget	$147,500

6.8 c) Phase III Extra to Add

Assigned load allocation efficiency control, to 6.8b above (cannot be applied to 6.8a) for all five boilers.

Installed	$ 20,000

NOTE: Software costs only required.

Engineering Cost Estimate	
Office design	$ 3,000
Field supervision	2,000
Keen	$ 5,000
Budget addition to 6.8b above.	$ 25,000

6.8 d) Phase IV Add

Complete new distributed control system, electronic transmitters and control room for 5 boilers.

Installed	$405,000
10% contingency	40,000
Deduct 80% of Phase II	(118,000)
New Control Room	$ 22,000
Budget Sub Total	$354,000
Engineering Cost Estimate	
Office design	$ 35,000
Field Supervision	10,000
Keen	$ 45,000
Total Budget	$399,000

Budget Costs are for

F.O.B. site, installed, with commissioning service, estimates included.

6.8 e) Phase V Burner Safety Systems

Budget cost estimate to replace existing with new solid state burner safety systems (5 boilers).	$167,000
10% contingency	17,000
Installed	$184,000
Engineering Cost Estimate	
Office design	$ 14,000
Field Supervision	$ 5,000
Keen	$ 19,000
Total Budget	$203,000

NOTE: New safety equipment included throughout including new valves but reuses existing safety switches.

6.9 Application of Economisers/Air Heaters to Boilers No. 1 & 5

Both units are operating without the benefit of heat recovery.

In both cases the application of an feedwater economiser would be more easily accomplished in physical terms than the installation of an air heater, with approximately the same basic efficiency gain of about 4% at full load.

Feedwater pressures are adequate since boiler #4 is already equipped with an economiser. Nos. 2 and 3 have air heaters.

The installation of an economiser at No. 1 boiler (100,000 lbs/hr) will be more difficult that at No. 5 (75,000 lbs/hr) because of the complexity of adjacent plant to No. 1 boiler and somewhat difficult access.

For #5 unit the economiser installation is more straightforward.

6.9 a) # 1 Boiler Economiser Performance - Expected

Based on an economiser configuration an efficiency increase of 4% is expected on gas and/or oil firing.

Economiser

Weight - 15,500 lbs
Surface - 4,800 sq. ft.
Pressure drop flue gas - 0.68" W.C.
Pressure drop waterside - 9.0 psi.

Note

Present boiler feed pump pressures are adequate to handle economiser requirements.

6.9 b) #5 Boiler Economiser Performance - Expected

Predicted fuel to steam efficiency improvements at full load follows:

75,000 lbs/hr

Natural Gas	79.46%	(without economiser)
	83.58%	(with economiser)
Efficiency Increase	4.11%	
Fuel Oil	82.03%	(without economiser)
	86.29%	(with economiser)
Efficiency Increase	4.26%	

We would expect the efficiency improvement to be maintained between 50% to 100% loads.

This boiler when required will normally be used at 100% load owing to its simplistic combustion control set up. (i.e. Parallel, electric, jackshaft, etc.)

5 Boiler

Furnace Heat release:

Natural Gas	52,261 BTU/hr/cu ft
* Natural Gas	53,494 BTU/hr/cu ft
Oil	54,505 BTU/hr/cu ft
* Oil	51,815 BTU/hr/cu ft

* With economiser

6.9 c) F.D. Fans

Must be checked for margin.

6.9 d) Air Preheaters for #1 and #5 Boilers

In view of the recent advent of the AREX air preheater - North Atlantic Technology Inc. - (to permit a greater heat gain by reducing stack gases below dew point levels) quotations were obtained for their supply, as follows:

	#1 Boiler	#5 Boiler
Flue gas temp. in/out Deg. °F	460/265	510/280
Air Temp. in/out °F	75/300	75/340
Heat transfer BTU/hr	5.2×10^6	4.7×10^6
* Estimated heat input boiler BTU/hr	121.8×10^6	93.05×10^6
Approximate fuel saved at full load %	4.26 %	5.05 %

* variable on account of natural gas BTU variations.

While it would appear that the air preheaters may have a slight edge on the economisers the cost and difficulty of installation is greater as F.D. fans at both boilers must be relocated from boiler front at drum level to the cold side of the air heater which also requires a separate structural support. Fan margins must be reviewed.

6.10 Economiser Budget Estimates

6.10 a) #1 Boiler Economiser

Economiser	$ 31,000
Piping valves	
Instruments	
Insulation	
Safety Valves	
Support Structure	37,000
Flue gas connection	
Sub Total	$ 68,000
+ 10% Overhead Profit	$ 6,800
+ 10% Contingency	7,480
+ 10% Engineering Fee	8,228
	$ 90,508
Say	$ 90,000

6.10 b) #5 Boiler Economiser

Economiser	$ 27,100
Piping Valves	
Instruments	
Insulation	
Safety Valves	
Flue Gas Connection	34,000
Sub Total	$ 61,100
+ 10% Overhead & Profit	6,110
+ 10% Contingency	6,721
+ 10% Engineering Fee	7,395
	$ 81,324
Say	$ 82,000

6.11 Air Preheater Budget Estimates

	a) #1 Boiler	b) #5 Boiler
Air heaters	$ 44,000	$ 37,000
Relocate F.D. Fan Structure Ducts and Breechings Electrics etc.	50,000	50,000
	$ 94,000	$ 87,000
10% overhead & profit	9,400	8,700
+		
10% contingency	10,340	9,570
+		
10% Engineering Fee	11,374	10,527
	$125,114	$115,797
Say	$125,000	$116,000

6.12 Air Heater/Economiser Applications - Payback

6.12 a) #1 Boiler

If No. 1 boiler is used for a total of 2928 hours per year at a saving of 4.26% of fuel input the current value of fuel saved is approvimately $55,000/yr., at an installed cost of $125,000, the simple payback aspect is 2.7 years.

6.12 b) Above is based on full load use throughout June, July, August and September only.

Savings at 4.26% =

$$\frac{2928 \text{ hrs}}{1050 \text{ BTU/cu ft}} \times \frac{121.8 \times 10^6 \text{ BTU}}{1000} \times \frac{\$3.83/1000 \text{ cu ft}}{} \times$$

$$\frac{4.26}{100} = \$55,416/\text{period}.$$

6.12 c) Economiser Application - #1 Boiler

If No. 1 boiler is used for a total of 2928 hours per year at a saving of 4% of fuel input, the current value of fuel saved is approximately $52,000, at an installed cost of $90,000, the simple payback aspect is 1.75 years.

$$\frac{2928 \text{ hrs}}{1050 \text{ BTU/cu ft}} \times \frac{121.8 \times 10^6 \text{ BTU/hr}}{1000} \times \frac{\$3.83/1000 \text{ CF}}{} \times$$

$$\frac{4}{100} = \$52,034/\text{period}.$$

6.12 d) Air Heater Application $5 Boiler

If No. 5 boiler is used for a total of 2928 hours per year at a savings of 5.05% of fuel input the current value of fuel saved is approximately $50,000, at an estimated cost of $116,000, the simple payback aspect is 2.3 years.

Above is based on full load use throughout June, July, August and September only.

Savings at 5.05% =

$$\frac{2928 \text{ hrs}}{1050 \text{ BTU/cu ft}} \times \frac{93{,}055{,}000 \text{ BTU/hr}}{1000} \times \frac{\$3.83/1000 \text{ CF}}{} \times$$

$$\frac{5.05}{100} = \$50{,}189/\text{period}.$$

6.12 e) Economiser Application #5 Boiler

If No. 5 boiler is used for a total of 2928 hours per year at a savings of 4.1% of fuel input, the current value of fuel saved is approximately $41,000, at an installed cost of $82,000, the simple payback aspect is 2 years.

$$\frac{2928 \text{ hrs}}{1050 \text{ BTU/CF}} \times \frac{93{,}055 \times 10^6}{1000} \times \frac{3.83}{} \times \frac{4.1}{100} =$$

$40,747/period.

6.13 a) Estimated Detailed Engineering Costs

Estimated detailed engineering costs for the implementation of the recommended modifications which are as noted in 4.2 and 4.3 herein.

Phase II	$ 15,000
Phase III	5,000
	$ 20,000

b) Estimated Contract Retrofit Costs

Estimated contract retrofit costs based on the proposed engineering details of the recommended modifications.

Phase II	$132,500
Phase III	20,000

c) Estimated Costs - Monitoring and Maintenance

Estimated costs of a nine month monitoring and maintenance of the upgraded facility.

5 hrs/week at $56/hr	
36 weeks	$ 12,096
Equipment maintenance	3,000
	$ 15,000

APPENDIX A

STATEMENT OF WORK

Keen Engineering Co. Ltd. were awarded a contract under D.S.S. File No. 03 SQ. 23440-3-9106-5 effective date of commencement January 12, 1984 for completion by May 31, 1984.

The Statement of Work, entitled Appendix 'A' in the contract, is as follows:

You shall provide a detailed pre-engineering evaluation of the potential for cost effective retrofit of the Central Heat Distribution Limited plant in Vancouver, B.C. by performing the following:

(a) Conduct site investigation and tests to establish data on fuel use, furnace combustion and system efficiencies, process load characteristics with time, etc.

(b) Conceptualise equipment upgrading and retrofit procedures to improve efficiencies and estimate cost/benefit impact.

(c) Estimate the project costs at the above site of implementing modifications and monitoring performance in the following stages:

<u>Stage I</u> A detailed engineering plan for modifications and costs for Stages II and III

<u>Stage II</u> A retrofit of equipment and commissioning and acceptance by the owner of upgrading systems

<u>Stage III</u> A nine (9) month monitoring and maintenance of the upgraded faculty.

APPENDIX B

SCOPE OF WORK

The 'Scope of Work' as interpreted and developed by Keen Engineering Co. Ltd. from the 'Statement of Work' originated by D.SS/EMR is outlined below.

a) To conduct on site combustion/efficiency enhancement tests and document potential fuel savings.

b) Propose appropriate equipment upgrading and retro fitting of instrumentation and controls to provide the maximum benefit consistent with plant operating requirements.

c) To review and comment on plant constraints which must be considered, so that 2.2 above can be achieved in a realistic and economic manner.

Stage I To estimate detailed engineering costs for the implementation of the recommended modifications.

Stage II To estimate the contract retrofit costs based upon the proposed engineering details of the recommended modifications.

Stage III To estimate the costs of a nine month monitoring and maintenance of the upgraded facility.

APPENDIX C

NATURAL GAS SUPPLY - BTU VARIATION

The attached B.C. Hydro sample records (2 pages) of BTU variations in the natural gas supply in Vancouver B.C., are of considerable interest in the pursuit of efficiency - and safety.

The visible evidence for June and August '83 indicates a range of 10.5% change in BTU content.

At 10% excess air firing natural gas the possibility of accidentally reaching stoichiometric and explosive conditions is evident and depends upon the initial BTU content at setting up of the combustion system. Under the same conditions the possibility of wasting up to 10% energy is also evident and can only be prevented by the incorporation of combined O_2 and combustibles trim analysis as we have recommended.

1110.7
1004.8
105.9

$\frac{105.9}{1004.8} = 10.54\%$ VAR.

AUG '83

PLANT	RELATIVE DENSITY	MJ/M^3	
	.616	41.15	
	.619	41.30	
	.617	41.18	
	.620	41.30	
	.618	41.22	
	.620	41.22	
	.620	40.73	1094.3
	.619	40.88	
	.618	40.77	
	.617	40.84	
	.619	41.15	
	.621	41.34	1110.7 BTU/cu ft. (1.5%)
	.622	41.22	
	.620	40.99	
	.620	41.15	
	.620	41.11	
	.619	41.11	
	.619	41.11	
	.618	40.96	
	.617	40.99	
	.617	41.18	
	.617	40.96	
	.618	40.99	
	.618	41.11	
	.619	41.07	
	.617	41.15	
	.617	41.07	
	.619	41.15	
	.618	41.03	
	.617	41.18	
	.616	40.96	
	.618*	41.08*	1103.7

JUNE '83

RELATIVE DENSITY	MJ/M^3		H.H.V. Btu/ft^3
.573	38.42	÷ .03722 =	1032
.573	38.42		
.574	38.46		
.574	38.49		1034.1
.562	37.62		
.562	37.43		
.562	37.43		
.561	37.40		1004.8
.561	37.43		
.570	37.93		
.575	38.30		
.577	38.38		
.578	38.34		
.577	38.27		
.577	38.38		
.574	37.85		
.579	38.19		
.579	38.30		
.577	38.38		
.576	38.30		
.577	38.30		
.577	38.27		
.577	38.34		
.576	38.38		
.576	38.42		
.576	38.38		
.577	38.42		
.578	38.46		
.578	38.42		
.582	38.91		

3%

.574* 38.20* - 1026.3

APPENDIX D

COMPRISING

Boiler Test Data Sheets - 4

Data Form: A combustion handbook for Canadian Fuels 1983, Vol. 2, Gaseous Fuels.

- pages 13 thru 15, Sample calculations.
- pages 21 thru 29, Fuel 1007 and combustion data.

TEST DATA SHEET

CONTRACTOR CENTRAL HEAT LTD

ULTIMATE CUSTOMER

LOCATION VANC BC

BOILER No. 1

~~NO~~ GAS

~~S.O. No.~~ FIRING

DATE APRIL 13/84

BY: J G GRANT

Time	ST Flow	ST Press	ST Temp	FGT	Air Temp	Gas Flow	Air Flow	Gas Temp	Gas Press	O2 Bailey	O2 K-M	FWT	Stm. Back Press
9:15	42	230	Sat'd	422	70	49	49	55	11.0	3.3	3.2	220	11.8
9:30	42	230	Sat'd	419	70	49	45	55	11.0	1.1	1.5 *	220	To 12.2
			* Trace of CO										
1030	86	230	D.S.	505	70	105	109	55	11.0	3.5	3.3 *	220	12.0

CO = 200 → 300 ppm @ 3.5% O2
Problem to be investigated before
further testing.

Form LSL-8 668

App D

TEST DATA SHEET

CONTRACTOR: CENTRAL HEAT LTD

ULTIMATE CUSTOMER: _____ BOILER No. 2 No _____ DATE: APRIL 16/84

LOCATION: VANC BC S.O. No. _____ BY: J G GRANT

Time	ST ET Flow	ST ET Press	ST Temp	FGT	Air Temp	Gas Flow	Air Flow	Gas Temp	Gas Press	O2 Bailey	O2 K-M	FWT	Back Press	Air In	Air Out	Gas In	Gas Out
9:00	53	220	SAT	462	75	56	56	55	11.5	3.4	3.2	220	120	75	330	462	218
7:00	53	220	SAT	460	75	56	50	55	11.5	1.5	1.9	221	11.5	75	330	460	218
10:00	86	225	SAT	545	75	98	02	55	11.5	4.0	3.9	221	120	75	370	545	245

Form 1 SDR-68A

TEST DATA SHEET

APP D

CONTRACTOR CENTRAL HEAT LTD

ULTIMATE CUSTOMER

LOCATION VANC BC

BOILER No. 3

No GAS

S O No FIRING

DATE APRIL 12/84

BY: J G GRANT

Time	ST Flow	ST Press	ST Temp	FGT	Air Temp	Gas Flow	Air Flow	Gas Temp	Gas Press	O2 Bailey	O2 K-17	FWT	Air In	Air Out	FG In	FG Out	St. Back Press
0:30	63	230	Sat'd	450	245	72	72	55	24	4.5	4.4	220	75	245	450	330	11.5 To 11.8
1:45	63.5	230	"	442	242	72	65	55	24	1.8	2.0*	220	75	242	442	315	
4:15	109	230	Sat'd	526	275	126	126	55	24	3.2	3.3	220	75	275	526	360	11.6 To 12.0
4:45	111	230	"	519	265	126	120	55	24	1.2	1.5	220	75	265	519	350	

* TRACE OF CO @ 1.7 → 1.9 % O2
CO = 100 ppm

AIR HEATER READINGS

Form LSD8 668

TEST DATA SHEET

CONTRACTOR: CENTRAL HEAT LTD

ULTIMATE CUSTOMER: _____ BOILER No. 4 ~~No~~ GAS DATE: APRIL 12/84

LOCATION: VANC BC ~~S.O. No~~ FIRING BY: J G GRANT

	ST FLOW	ST PRESS	ST TEMP	FGT	AIR TEMP	GAS FLOW	AIR FLOW	GAS TEMP	GAS PRESS	O2 BAILEY	O2 K-M	FWT	FW IN	FW OUT	FG IN	FG OUT	ST. BACK PRESS
1:45	161	230	SAT'D	562	75	179	179	50	25	3.3	3.2	270	220	270	562	370	11.5 To
1:45	163	230	"	555	75	179	165	50	25	1.0	1.3	268	220	268	555	360	12.0
													ECONOMIZER READINGS				
2:00	93	230	SAT'D	475	75	104	104	50	25	3.4	3.4	262	218	262	475	312	11.5 To
2:00	94	230	"	469	75	104	101	50	25	1.0	1.3	261	217	261	469	307	11.8

Form LSUR 668

D

APPENDIX A

SAMPLE COMBUSTION AND HEAT LOSS CALCULATIONS

A.1. Fuel Properties

Fuel: Natural Gas, 1007 Btu/cu ft

A.1.1 Analysis, % by volume

Methane	(CH_4)	91.57
Ethane	(C_2H_6)	5.01
Propane	(C_3H_8)	0.25
Normal butane	(C_4H_{10})	Trace
Iso-butane	(C_4H_{10})	0.01
Normal pentane	(C_5H_{12})	Trace
Iso-pentane	(C_5H_{12})	Trace
Hexanes plus	(C_6H_{14} +)	Nil
Nitrogen	(N_2)	2.67
Carbon dioxide	(CO_2)	0.49
Oxygen	(O_2)	Nil
Hydrogen	(H_2)	Nil
	TOTAL	100.00

Total Sulphur (including 0.12 gr/Scf as odorant) = 0.23 gr/Scf

Sp. Gr. relative to air:	0.598
lb/cu ft at 29.92 in. Hg and 60°F:	0.0456
Calorific value at 29.92 in. Hg and 60°F:	1,007

A.1.2. Ultimate Analysis, lb/lb

Wt of carbon = 0.9157 X 12.011 + .0501 X 24.022 + .0025 X 36.033 + .0001 X 48.044 + .0049 X 12.011 = 12.356

Wt of hydrogen = .9157 X 4.032 + .0501 X 6.048 + .0025 X 8.064 + .0001 X 10.08 = 4.015

Wt of nitrogen = .0267 X 28.016 = 0.748

Wt of oxygen = .0049 X 32 = 0.157

Total wt = 17.276

∴ Ultimate analysis, lb/lb fuel:

carbon:	0.716
hydrogen:	0.232
nitrogen:	0.043
oxygen:	0.009
	1.000

A.2. Combustion Calculations. (Assuming atmospheric pressure = 29.92 in. Hg)

A.2.1 Stoichiometric air required

Wt of fuel per 10^6 Btu = $\frac{10^6}{1{,}007}$ X 0.0456 = 45.28 lb

Combustible			*O_2 from air, lb*
C	2.667 X 0.716 X 45.28	=	86.44 (CO_2)
H_2	8.000 X 0.232 X 45.28	=	84.04 (H_2O)
	Total		170.48
	Less O_2 in gas, 0.009 X 45.28	=	0.41
	O_2 from air, lb/10^6 Btu	=	170.07
	Associated N_2 = $\frac{76.85}{23.15}$ X 170.07 =		564.57
	Dry air, lb/10^6 Btu		734.64

A.2.2. Combustion air for a range of total air

Sp vol of dry air at 40°F = 12.59 cu ft/lb dry air
60°F = 13.10
80°F = 13.60
100°F = 14.11
120°F = 14.62

Total air, %	100	140	160	200
Dry air, lb/10^6 Btu	734.6	1028.5	1175.4	1469.3

Air temp, °F	*Dry air, cu ft/10^6 Btu*			
40	9,249	12,950	14,800	18,500
60	9,624	13,470	15,400	19,250
80	9,991	13,990	15,980	19,980
100	10,370	14,510	16,580	20,730
120	10,740	15,040	17,180	21,480

A.2.3. Stoichiometric products of combustion by wt

Dry fuel and dry air basis

Dry products		*lb*
CO_2 = 0.716 X 45.28 X $\frac{44.01}{12.01}$	=	118.80
N_2 from air	=	564.57
N_2 from fuel = 0.043 X 45.28	=	1.95
Dry flue gas, lb/10^6 Btu	=	685.32
Wet products		
H_2O = 0.232 X 45.28 X $\frac{18.02}{2.02}$	=	93.71
Total flue gas,* lb/10^6	=	779.03

*The term "total flue gas" is taken to mean the dry products plus the moisture from the combustion of hydrogen but excluding moisture from fuel or air.

A.2.4. Products of combustion and % CO_2 for a range of total air

At stoichiometric

$$\text{lb}/10^6\ \text{Btu} \quad \text{Mol wt} \times \text{Mol vol} = \frac{\text{cu ft at } 32^\circ\text{F}}{10^6\ \text{Btu}}$$

Dry products

CO_2 118.8 ÷ 44.01 × 359 = 969.1

N_2 566.5 ÷ 28.01 × 359 = 7260.7

Total dry products, cu ft at 32°F/10^6 Btu = 8229.8

Wet products

H_2O 93.7 ÷ 18.02 × 359 = 1866.7

Total flue gas, cu ft at 32°F/10^6 Btu = 8230 + 1867 = 10,097

For 20% excess air

Additional O_2 = 0.2 × 170.1 ÷ 32.00 × 359 = 381.7
Additional N_2 = 0.2 × 564.6 ÷ 28.01 × 359 = 1447.3
Additional dry products, lb/10^6 Btu = 146.93
Additional dry products, cu ft at 32°F/10^6 Btu = 1829.0
CO_2, cu ft at 32°F/10^6 Btu = 969.1
O_2, cu ft at 32°F/10^6 Btu/each 20% of excess air = 381.7

Total air, %	Dry flue gas lb/10^6 Btu	Dry flue gas cu ft at 32°F / 10^6 Btu	Total flue gas lb/10^6 Btu	Total flue gas cu ft at 32°F / 10^6 Btu	CO_2, % by vol dry gas basis	O_2, % by vol dry gas basis
100	685.3	8,230	779.0	10,100	11.78	0
120	832.2	10,060	926.0	11,930	9.63	3.79
140	979.2	11,890	1073	13,760	8.15	6.42
160	1126	13,720	1220	15,580	7.06	8.35
180	1273	15,550	1367	17,410	6.23	9.82
200	1420	17,380	1514	19,240	5.58	10.98

A.2.5. Volume of products of combustion for a range of total air and temperature

Correction for 200°F	$= \frac{460 + 200}{460 + 32}$	= 1.3415
250°F		1.4430
300°F		1.5447
350°F		1.6463
400°F		1.7480
450°F		1.8496
500°F		1.9512
550°F		2.0528
600°F		2.1544
650°F		2.2560

Total flue gas, cu ft/10^6 Btu

Gas temp, °F \ Total air, %	100	140	160	200
32	10,100	13,760	15,580	19,240
200	13,550	18,500	20,900	25,810
250	14,570	19,860	22,480	27,760
300	15,600	21,260	24,070	29,720
350	16,630	22,650	25,650	31,680
400	17,660	24,050	27,230	33,630
450	18,680	25,450	28,820	35,590
500	19,710	26,850	30,400	37,540
550	20,730	28,250	31,980	39,500
600	21,760	29,640	33,570	41,450
650	22,790	31,040	35,150	43,400

A.3 Heat Loss Calculations

A.3.1. Dry flue gas loss

$$\text{In Btu}/10^6\ \text{Btu} = \frac{\text{lb dry gas}}{10^6\ \text{Btu}} \times 0.24 \times (\text{stack temp} - \text{combustion air temp})$$

In % = above × 100 ÷ 10^6

Heat loss, %

Stack temp. − Comb. air temp., °F \ Total air, % / lb dry gas / 10^6 Btu	100 / 685.3	140 / 979.2	160 / 1126	200 / 1420
100	1.64	2.35	2.70	3.41
150	2.47	3.52	4.05	5.11
200	3.29	4.70	5.40	6.82
250	4.11	5.88	6.76	8.52
300	4.93	7.05	8.11	10.22
350	5.76	8.22	9.46	11.93
400	6.58	9.40	10.81	13.63
450	7.40	10.58	12.16	15.34
500	8.22	11.75	13.51	17.04
550	9.05	12.93	14.86	18.74
600	9.87	14.10	16.21	20.45
650	10.69	15.28	17.57	22.15

A.3.2. Heat loss due to combustion of H_2

In Btu/10^6 Btu, if stack temp. is below 575°F

$$= \frac{\text{lb } H_2O \text{ formed}}{10^6\ \text{Btu}} \times (1089 - \text{comb. air temp.} + 0.46\ (\text{stack temp}))$$

In Btu/10^6 Btu, if stack temp. is above 575°F

$$= \frac{\text{lb } H_2O \text{ formed}}{10^6\ \text{Btu}} \times (1066 - \text{comb. air temp.} + 0.50\ (\text{stack temp}))$$

In % = above × 100 ÷ 10^6

$$\frac{\text{lb } H_2O \text{ formed}}{10^6\ \text{Btu}} = 93.71$$

Heat loss, %

Stack temp. °F	Combustion air temp., °F 40	60	80	120
200	10.69	10.50	10.32	9.94
250	10.91	10.72	10.53	10.16
300	11.12	10.94	10.75	10.37
350	11.34	11.15	10.96	10.59
400	11.55	11.37	11.18	10.80
450	11.77	11.58	11.40	11.02
500	11.99	11.80	11.61	11.24
550	12.20	12.01	11.83	11.45
600	12.43	12.24	12.05	11.68
650	12.66	12.47	12.28	11.91

A.3.3. Heat loss due to CO

$$\text{Heat loss in Btu/}10^6\text{ Btu} = \frac{CO}{CO_2 + CO} \times 10{,}160 \times \frac{\text{lb carbon}}{10^6\text{ Btu}}$$

Heat loss in % = above × 100 ÷ 10^6

Assume complete mixing, i.e. CO_2 + CO always = 11.78

CO, %	*Heat loss, %*
0.5	1.40
1.0	2.80
1.5	4.19
2.0	5.59

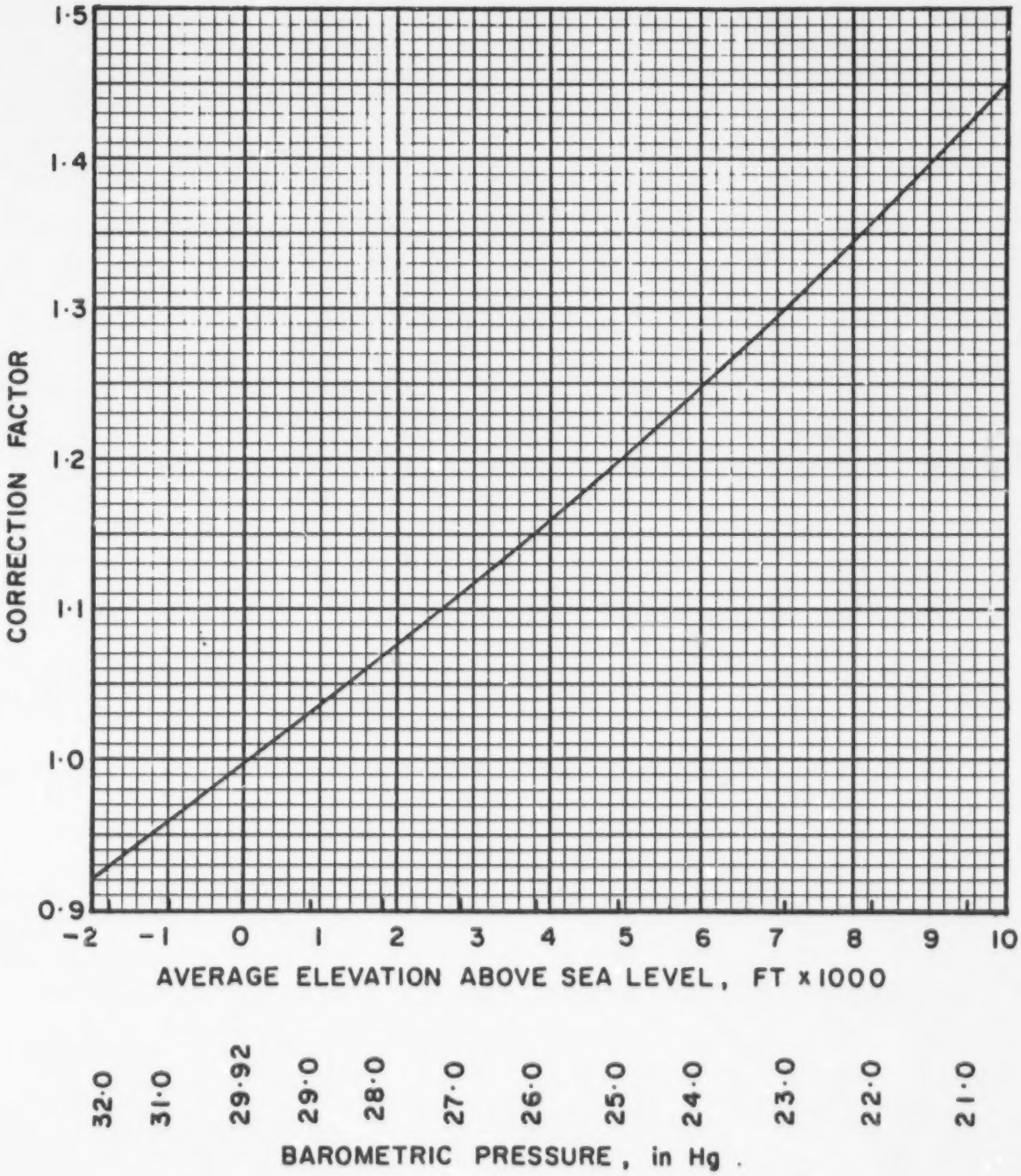


FIGURE A. ELEVATION CORRECTION FACTORS TO BE APPLIED TO THE VOLUMES OF COMBUSTION AIR AND FLUE GAS OBTAINED FROM FIGURE 2 WHEN ATMOSPHERIC PRESSURE IS OTHER THAN 29·92 in Hg.

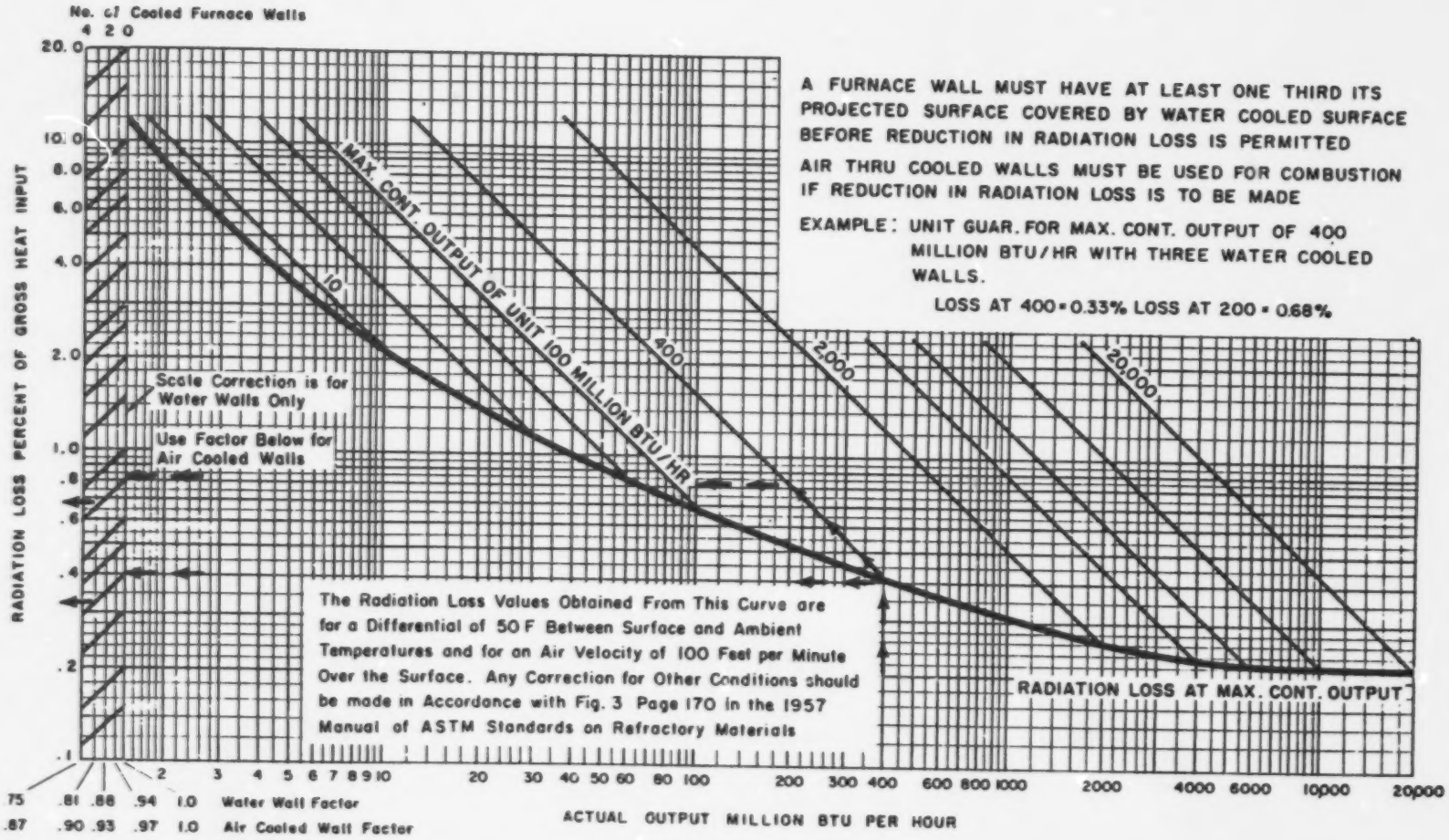


FIGURE B. RADIATION AND CONVECTION HEAT LOSS CHART, ASSUMING EMISSIVITY = 0·95
PUBLISHED BY COURTESY OF THE AMERICAN BOILER MANUFACTURERS ASSOCIATION.

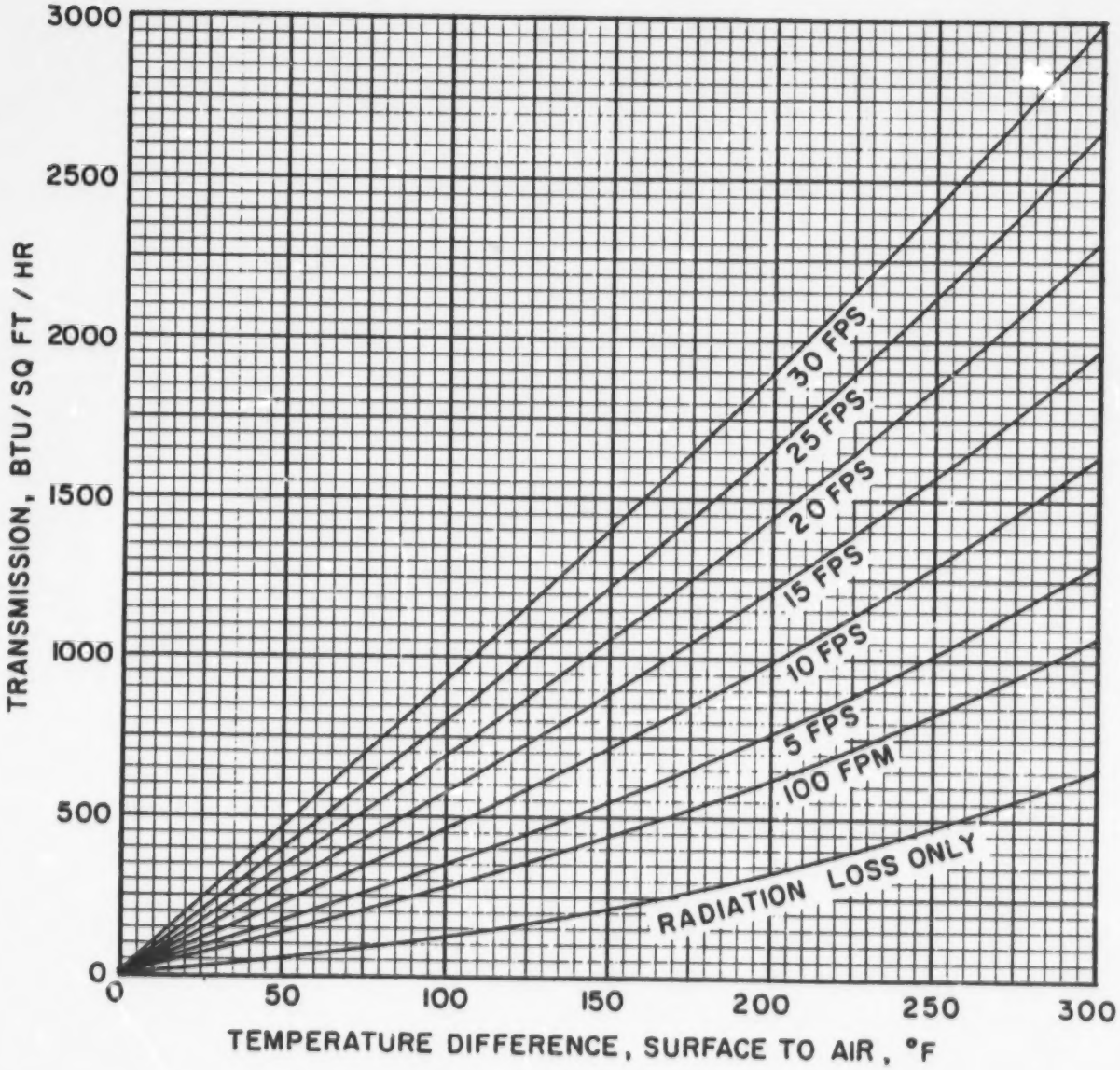


FIGURE C. SURFACE HEAT TRANSMISSION FOR A RANGE OF AIR VELOCITIES BASED ON AN EMISSIVITY OF 0·95 AND AN AIR TEMPERATURE OF 70° F. PUBLISHED BY COURTESY OF THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS.

D

FUEL 1007 NATURAL GAS

Analysis, mole %

Methane	(CH_4)	91.57
Ethane	(C_2H_6)	5.01
Propane	(C_3H_8)	0.25
N-butane	(C_4H_{10})	Trace
Iso-butane	(C_4H_{10})	0.01
N-pentane	(C_5H_{12})	Trace
Iso-pentane	(C_5H_{12})	Trace
Hexanes plus	(C_6H_{14}+)	Nil
Nitrogen	(N_2)	2.65
Carbon dioxide	(CO_2)	0.49
Oxygen	(O_2)	Nil
Hydrogen	(H_2)	Nil
	TOTAL	100.00

Total sulphur (including 0.12 gr/100 cu ft at odorant)
= 0.23 gr/100 cu ft.

Note: The following data apply under standard conditions of 60°F and 29.92 in. Hg.

Specific gravity relative to air:	0.598
Specific weight, lb/cu ft:	0.0456
Specific volume, cu ft/lb:	21.93

Calorific Value

Btu/cu ft of gas:	1007
Btu/lb of gas:	22,080

Conversion Factors

10^6 Btu = 993.0 cu ft of gas
10^6 Btu = 45.28 lb of gas

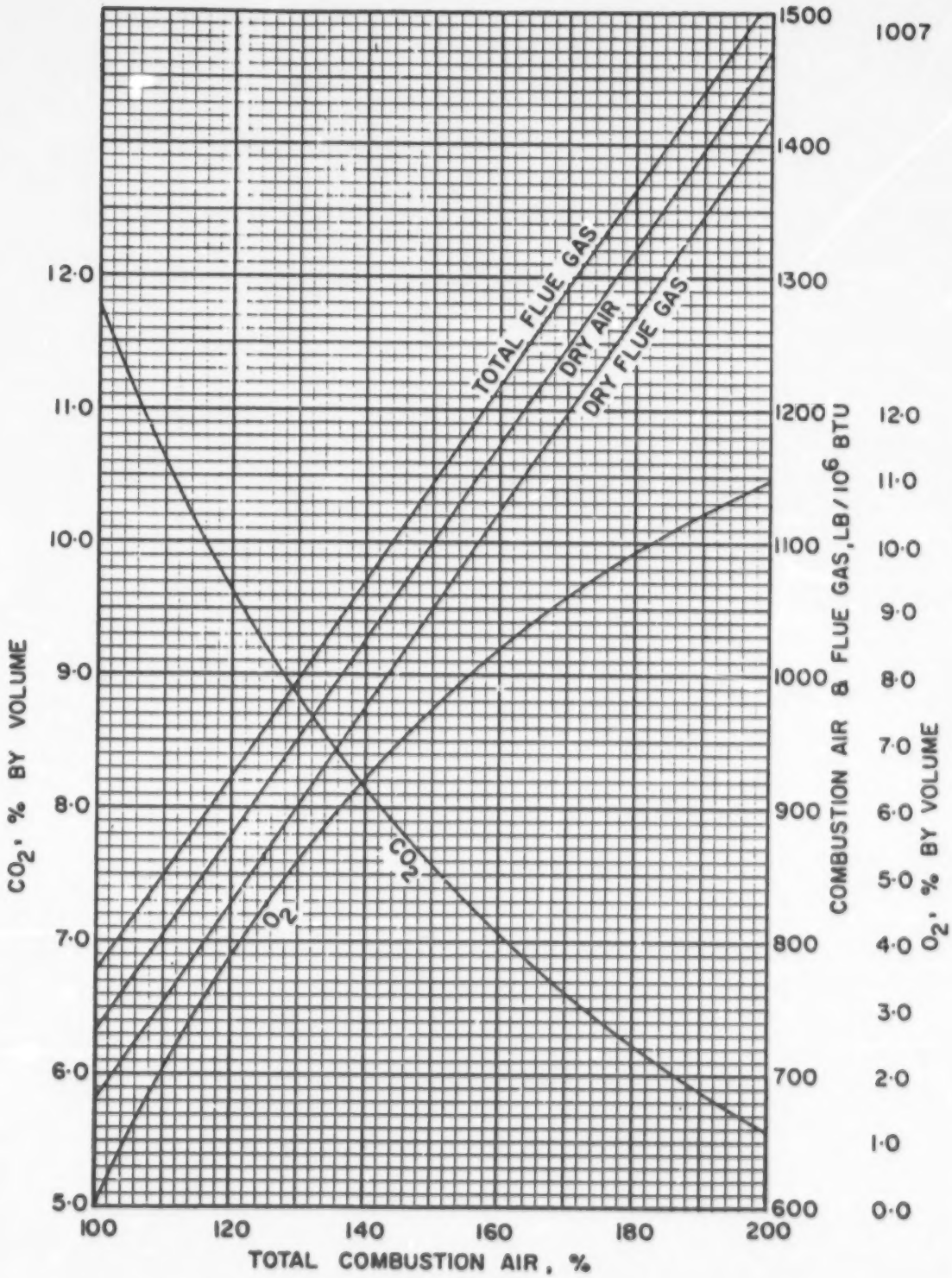


FIGURE 1: COMBUSTION DATA, WEIGHT BASIS.
FUEL: NATURAL GAS, 1007 BTU/CU FT.

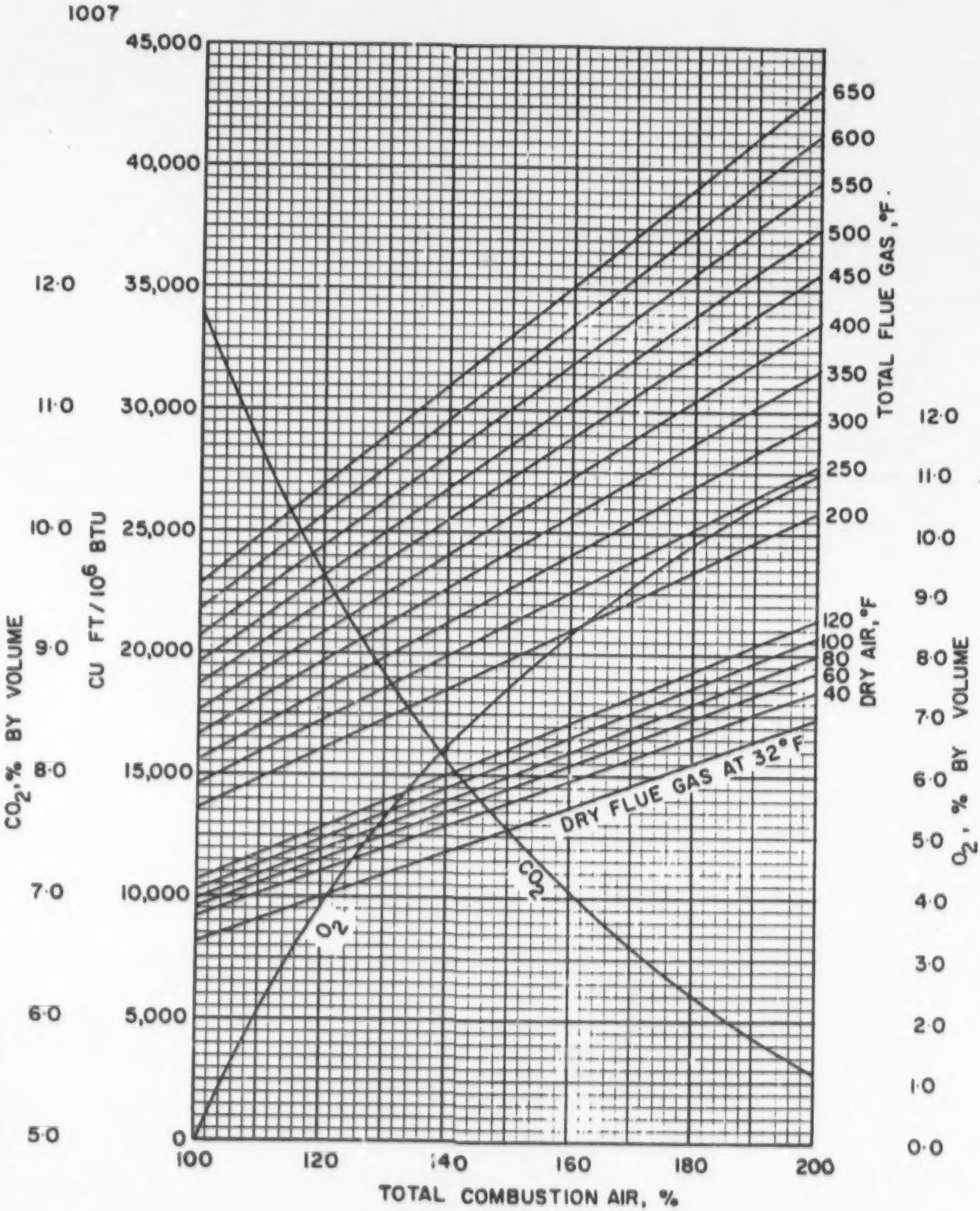


FIGURE 2: COMBUSTION DATA, VOLUME BASIS.
FUEL: NATURAL GAS, 1007 BTU / CU FT.

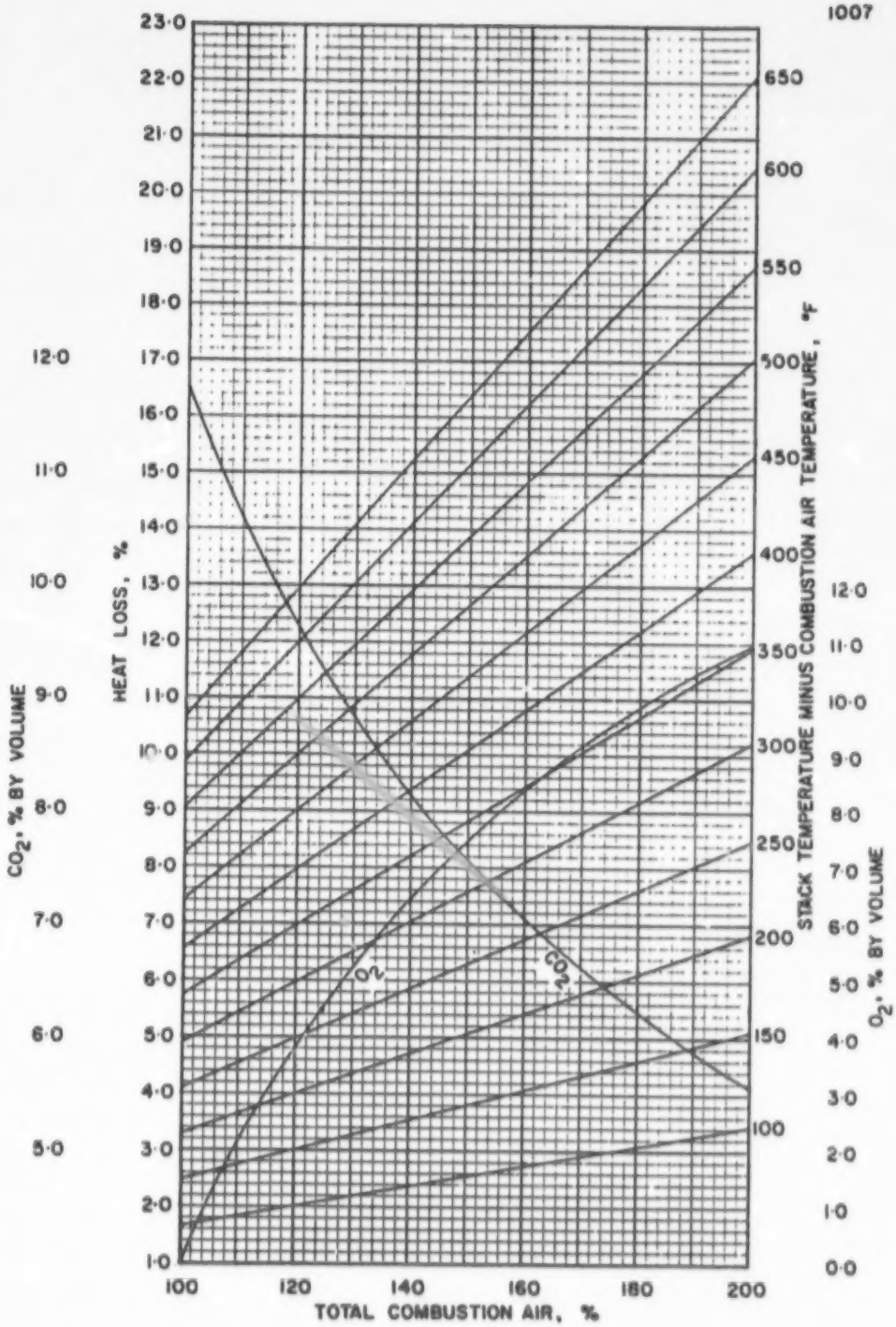


FIGURE 3· DRY FLUE GAS LOSS FOR A RANGE OF TEMPERATURE DIFFERENTIALS
FUEL: NATURAL GAS, 1007 BTU / CU FT

1007

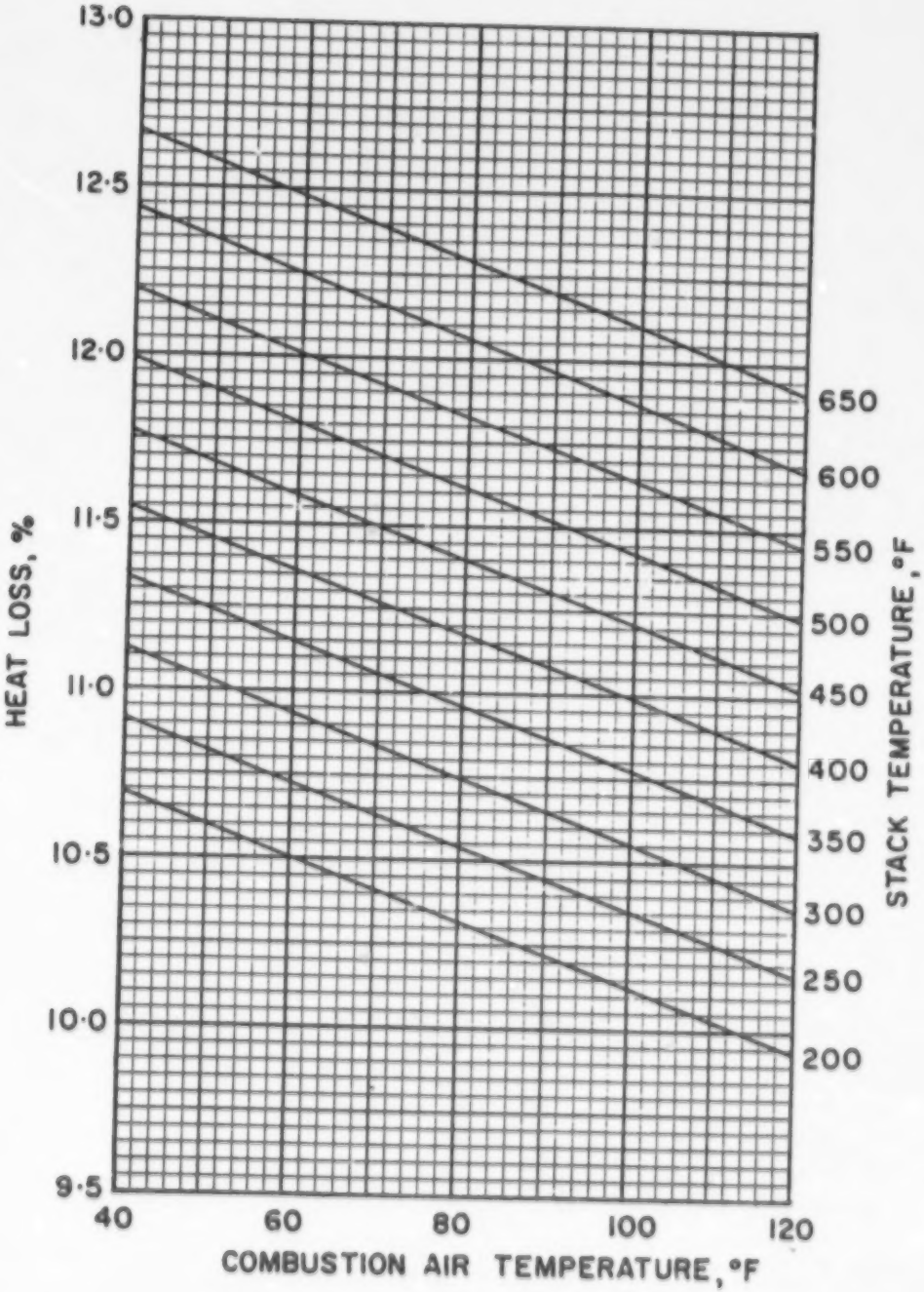


FIGURE 4: HYDROGEN LOSS FOR A RANGE OF STACK TEMPERATURES.
FUEL: NATURAL GAS, 1007 BTU/CU FT.

D

1007

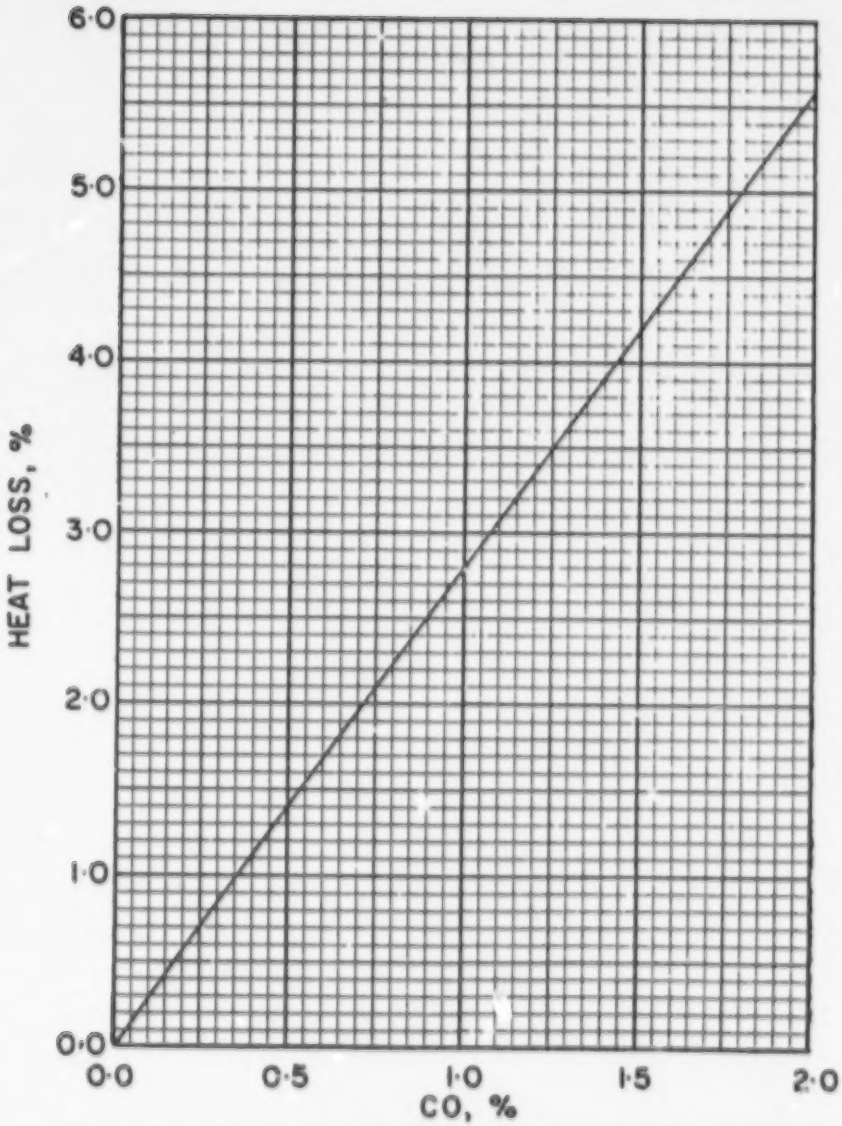


FIGURE 5· HEAT LOSS FOR A RANGE OF CO CONCENTRATIONS, ASSUMING NEGLIGIBLE EXCESS AIR.
FUEL: NATURAL GAS, 1007 BTU / CU FT

APPENDIX E

INPROHEAT INDUSTRIES LTD.

Letter March 16, 1984 to Keen Engineering Co. Ltd.

APP. 'E'

INPROHEAT
INPROHEAT INDUSTRIES LTD. / 680 RAYMUR AVENUE, VANCOUVER, B.C., CANADA V6A 2R1

TELEPHONE (604) 254-0461
TELEX: 04-51370
CABLE ADDRESS: INPROHEAT

March 16, 1984

Keen Engineering Co. Ltd.
Industrial Division
214-545 Clyde Ave.,
West Vancouver, B.C.
V7T 1C5

RECEIVED

Attention: Mr. J.G. Grant

RE: Central Heat
Your letter of March 8/84

Dear Jack:

On March 13th and 15th, I checked the calibration of Gas Flow and Steam Flow meters on Boilers 1,2, 3 and 4 at the Central Heating plant on Beatty St., per your request of March 8, 1984. Existing O_2 analyzers were also checked by comparison to a Teledyne model. All Flow meters were found to be in good working order and only minor adjustments were made in order to obtain best accuracy.

To be more specific, the following is a representation of the actual "as found" calibration.

#1	Gas Flow	Well within limits as found. No corrections made.
#1	Steam Flow	Okay as found. Recorder shows a slightly low zero but accuracy of meter as well as integrator, is fine at anything above zero. No corrections made.
#2	Gas Flow	Okay as found. No corrections made.
#2	Steam Flow	Found zero shifted up 2%. Correction made.
#3	Gas Flow	Meter zero is 3% high at zero flow. This appears to be necessary in order to obtain an accurate calibration.

OUR 25th YEAR

INPROHEAT

APP. 'E'

	The recorder zero was found set to 0 which produced a 3% low error across the range. When recorder indication is raised to coincide with transmitter, the calibration falls into line and no other corrections are necessary. This sort of condition is not altogether unusual for some CA13 meters and is generally difficult to correct. I feel the meter can be left alone as long as plant operations ensure the recorder is turned off when boiler is not in use.
#3 Steam Flow	Meter was 1½% low across range. Correction made. This meter is too slow returning to zero. Maintenance is indicated.
#4 Gas Flow	Okay as found. No correction made.
#4 Steam Flow	Meter found reading about 1½% high across the range. Correction made.

The plant at present has two O_2 analyzers in operation.

Comparisons were drawn between the plant's KAY MAY portable analyzer and the Inproheat Teledyne at O_2 level of approximately 4.5% and 10% respectively.

These two analyzers were found to agree to within 0.1% O_2 at both levels.

The Bailey analyzer was found to be in need of recalibration. Plant personnel will attend to this.

I would suggest the KAY MAY be used for any tests you might want to perform.

I trust you will find our efforts satisfactory. Please be in touch if you require further information.

Yours sincerely,
INPROHEAT INDUSTRIES LTD.

Hank Weverink,

HW:dja

APPENDIX F

BOILER MANUFACTURERS DATA AND PREDICTED PERFORMANCE SHEETS

The following manufacturers data pertaining to:

Boilers No. 1 and No. 2

1968 - Combustion tests
(Boiler No. 2 has Air Heater)

Boiler No. 3

1969 - Predicted Performance with installed Air Heater data

Boiler No. 4

1972 - Predicted Performance with installed Economiser data

Boiler No. 5

1983 - Predicted Performance
- No Economiser installed

F

BLR # 1

COMBUSTION TEST AND AIR FLOW ADJUSTMENT

[illegible] METER COMPANY LIMITED

1968 TEST.

COMPANY	Foster Wheeler	DATE	6 Nov. [illegible]
PLANT	Central [illegible]	S.O. No.	[illegible]
TYPE		H.	[illegible]
LOCATION	Vancouver, B. C.	Cust. Order	[illegible]

BOILER DATA

Boiler No.	1
Boiler Make	Foster Wheeler
Boiler Type	
No. Passes & Type Baffles	
Heating Surface in Sq. Ft.	
Economizer Type & Make	
Draft (Type as F.D. I.D. etc.)	F.D.
Air Heater Type & Make	
Feed Water Regulator Type & Make	[illegible]
Combustion Control Type & Make	[illegible]
Walls Type & Make	[illegible]
Furnace Volume in Cu. Ft.	
Burning Equipment Type & Make	

METER DESIGN DATA

Meter Type	[illegible] Cu. No.
[illegible]	
Temp. °F	
Max. Meter Capacity	[illegible]
Chart No.	
Type Pressure Element	
Air Flow	Displacer
Mechanism	Round Large [illegible]
Diaphragm	Rect. Small

FUEL DATA

Fuel Burned [illegible]

	1	2	3	4
[illegible]				
[illegible]				
[illegible] 1000 lbs/hr	13.2	54.0	72.0	102.0
[illegible] 1000	21.0	57.4	77.0	116.0
[illegible]	21.0	57.4	77.0	116.0
Steam Press. [illegible] psig	240	240	240	240
Steam Press. [illegible] psig	240	240	240	240
[illegible]	2.9"	9 oz.	1.8"	2.2"
Feed Water Temp. °F	220	220	220	220
Steam Temp. °F	Sat.	Sat.	Sat.	Sat.
[illegible] % by Volume				
[illegible] % by Volume	3.5	3.0	3.5	2.4
[illegible] % by Volume				
Total Air Tests %	17.5	15.0	17.5	12.0
Total Air Design %	17.5	15.0	17.5	12.0
[illegible]	400	450	480	540
[illegible]	60	61	60	60
Moisture [illegible] inches of water				
Windbox	1.0	3.5	5.0	11.0
Furnace Press.	0	1.0	1.5	6.2
Boiler [illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Reason for Selecting Total Air for all

Combustibles

Air Flow Mechanism Calibration

Radius 'R' = 2.72

Total Grams Inc. Pan	Chart Reading
10	12
30	20
60	29
110	40
160	49
210	56
260	62
310	68

F

BLR #2.

[illegible] TEST AND AIR FLOW ADJUSTMENT

BAILEY METER COMPANY LIMITED

1968 TEST.

COMPANY [illegible]
PLANT [illegible]
TYPE
LOCATION Vancouver, B. C.

BOILER DATA

Boiler No.	2
Boiler Make	[illegible]
Boiler Type	
Air Passes & Type Baffles	
Heating Surface in Sq. Ft.	
Economizer Type & Make	
Draft (Type as F.D., I.D. etc)	F.D.
Air Heater Type & Make	[illegible]
Feed-Water Regulator Type & Make	[illegible]
Combustion Control Type & Make	[illegible]
Walls Type & Make	[illegible]
Furnace Volume in Cu. Ft.	
Burning Equipment Type & Make	COMB

METER [illegible] DATA

[illegible]

Max Meter Capacity [illegible]

Chart No.

Type Primary Element

Air Flow

Diaphragm

Diameter

Large

Small

FUEL DATA

Fuel Burning [illegible]

	1	2	3	4
[illegible]	Nov.2/68	Nov.2/68	Nov.2/68	Nov.2/68
Steam Flow [illegible] X 1000 - lbs/hr	14.4	31.2	50.4	98.4
Steam Flow [illegible] X 1000 -	19.6	33.6	63.0	112.0
Air Flow (relative)	19.6	33.6	63.0	112.0
Steam Press. [illegible] psig	240	240	240	240
Steam Press. [illegible] psig	240	240	240	240
[illegible] Pressure	---	3½ oz.	9 oz/	2.0#
Feed Water Temp. °F	220	220	220	220
Steam Temp. °F	Sat.	Sat.	Sat.	Sat.
[illegible] by Volume				
[illegible] by Volume	3.5	3.5	2.7	2.1
[illegible] by Volume				
[illegible] Air (Test)	175	17.5	13.5	10.5
[illegible] Air (Fuel)	17.5	17.5	13.5	10.5
[illegible] Temp. °F	---	425	490	570
[illegible] Temp. °F	60	60	60	60
Manometer [illegible] inches of water				
Windbox				
Furnace Press.			3.3	14.
Boiler Out				10.25

Reason for Selecting Total Air [illegible]

Comparable.

Air Flow Mechanism Calibration

Radius 'R' = 2.5

Total Grams Inc. Pan	Chart Reading
10	12
30	22
60	32
110	43
160	53
210	62
260	70
310	75

Fuel Sliced to Meas. [illegible]

BLR #3 F

Number Furnished - One (1)

GENERAL DATA

Heating Surface - 6570 sq. ft.

Vertical Tubular - One pass gas one pass air

The Air Heater will include the following material:

Parts	Size	Length	Thickness
Elements	2"	14'0	0.083
Top & Bottom Plates	As Required		5/8 Thick

The tubes will be expanded into the top and bottom tube plates.

Supporting Steel

Supporting frame and columns to support the air heater from the ground floor level at height shown on Drawing V-3117 will be supplied by the Company.

Steel Casing

Single plate steel casing consisting of 3/16" thick steel plate with necessary stiffening members to form air heater enclosure. Openings in casing for air and flue gas to enter and leave provided with suitable frames for attachment of all ducts and gas flues. Provision will be made in casing design to allow for differential expansion between air heater parts.

Insulation

The steel casing will be insulated with 1" Uniblok and covered with 1/2 finish cement reinforced with wire mesh.

Corrosion Control

For low ambient temperature, low load operation or when firing high sulphur fuel a steam coil air heater will be provided to preheat the air and control corrosion.

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COL. 1 — EQUIPMENT AND FUEL

UNIT
- No. of Units: 1 — Type: Package
- Specific Designation: FMD13-83, 6,8,9
- Design Press. psig: 250 To ASME Code

S.H.
- Type:
- No. Gas Passes: — No. Steam Passes:

ECON.
- Type: — No. Gas Passes:
- Design Press. psig: — Make:

AIR HEATER
- Type: Tubular — Make: B&W Canada
- No. Gas Passes: 1 — No. Air Passes: 1 — Thru Elements: Gas

BURNER
- Make: B&W Canada Ltd. — No./Furnace: 1
- Type: Circular Oil & Gas

HEATING SURFACE

	ABMA — Sq. Ft.	Full Cir. Sq. Ft.	Furnace Volume
BOILER	7248	7622	
FURNACE	1018	2408	
TOTAL	8266	10030	2210 Cu. ft.

F.D. FAN
- Type: Centrifugal
- Net 136,800 Lbs./Hr. at 17.84 "Wg and 80 °F.
- T.B. 157,600 Lbs./Hr. at 20.6 "Wg and 105 °F.

STACK
- Height above: Ft. — Dia. at Top—In.
- Construction:

DRIVES

Equipment	H.P.	R.P.M.	Type	Electrics
F.D.Fan			Turbine	

FUEL AS FIRED

LIQUID		GASEOUS	
Fuel	No. 6 Oil	Fuel	Natural Gas
Analysis	Assumed	Analysis	Assumed
% by	Weight	% by	Volumn
Ash		CH_4	91.20
S	1.0	C_2H_6	1.33
H_2	9.2	C_3H_8	6.12
C	88.9	C_4H_{10}	0.37
H_2O		C_5H_{12}	0.04
N_2	0.9	C_6H_{14}	0.04
O_2		CO_2	
		O_2	
		N_2	0.90
TOTAL	100.0	TOTAL	100.00
B.T.U./lb.	18,200	B.T.U./cu. ft.	1078
		At 60°F, 30 in. Hg.	

Expected Performance is based on Comb. Air entering Unit at 80°F., 60% rel. Humidity, 0.013 Lb. Moisture/Lb. Dry Air, 29.29 in. Hg. Barometric Press. conditions and equipment given on this summary sheet and arrangement shown on Dwg. No. V-3117

COL. 2 — EXPECTED PERFORMANCE

	Steam-Actual-Continuous-M-lb./hr.	135	135
	Type of Fuel	Oil	Gas
	Burners - No. in use per unit	1	1
	Excess air leaving Boiler %	15	10
QUANTITIES M - LB./HR.	Continuous Blowdown	–	–
	Fuel (Gas - M SC FH)	8.74	156
	Flue Gas Leaving Air heater	145.5	144.0
	Air entering Airheater	137.0	136.8
PRESSURES LB./SQ. IN	Min. at Feed Inlet	262	262
	Drop thru FWR + Feed Valve	35	35
	Min. Oper. at Boiler Drum	227	227
	Drop from Drum to Boiler Outlet	7	7
	Steam at Boiler Outlet	220	220
TEMPERATURES °F	Steam	Saturated	
	Flue Gas Leaving Boiler	622	614
	" " " Economizer		
	" " " Air Heater	410	408
	Water Entering Unit	220	220
	" Leaving Economizer		
	Air Entering Air Heater	80	80
	" Leaving Air Heater	325	342
DRAFT LOSS IN. OF WATER	Boiler	5.18	5.26
	Economizer		
	Air Heater	1.82	1.92
	Flues	0.51	0.50
AIR RESIST. IN. OF WATER	Burner and Windbox	7.65	7.65
	Ducts	1.00	1.01
	Air Measuring Device		
	Steam Coil Air Heater	0.50	0.50
	Air Heater	0.95	1.00
	TOTAL (Net.)	17.61	17.84
HEAT LOSSES %	Dry Gas	6.81	5.94
	Hydrogen and Moisture in Fuel	5.44	11.12
	Moisture in Air	0.18	0.17
	Radiation	0.47	0.47
	Unacc. Loss and Mfrs. Margin	1.00	1.00
	Total Heat Loss	13.90	18.70
EFFICIENCY		86.1	~~81.3~~
Max. Allow. Boiler Conc. P.P.M.		3500	
Solids in Steam PPM		3	

REVISIONS	No.	Description	By	Date

By RWH Chk'd RJC No. V-3117 Date May 7/69

Contract No. 6680 Date May 7.1969 1

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BLR # 4 F

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COL. 1 — EQUIPMENT AND FUEL

UNIT

No. of Units	1
Type	PACKAGE
Specific Designation	FMD126-117,2,5A, 8,9
Design Press. psig.	300 TO A.S.M.E. CODE

S.H.

Type	
No. Gas Passes	
No. Steam Passes	

ECON.

Type	EXTENDED SURFACE
No. Gas Passes	1
Design Press. psig.	325
Make	KENTUBE

AIR HEATER

Type	
Make	
No. Gas Passes	
No. Air Passes	
Thru Elements	

BURNER

Make	B & W CAN. LTD
No./Furnace	2
Type	CIRCULAR OIL & GAS

HEATING SURFACE

	ABMA — Sq. Ft.	Full Cir. Sq. Ft.	Furnace Volume
BOILER	9870	10371	
FURNACE	1435	3390	
TOTAL	11305	13761	2900 Cu. ft.

F.D. FAN

Type	CENTRIFUGAL
Net	205,500 Lbs./Hr. at 22.5 "Wg and 80 °F.
T.B.	236,400 Lbs./Hr. at 29.25 "Wg and 105 °F.

STAC.

Height above	Ft. Dia. at Top—In.
Construction	

DRIVES

Equipment	H.P.	R.P.M.	Type	Electrics
F.D. FAN	150	1800	TURBINE	-
F.D. FAN	75	900	MOTOR	3/60/230

FUEL AS FIRED

LIQUID		GASEOUS	
Fuel	No. 5 Oil	Fuel	Natural Gas
Analysis	By Customer	Analysis	By Customer
% by	Weight	% by	Volume
Ash	-	CH_4	94.40
S	2.00	C_2H_6	0.65
H_2	11.35	C_3H_8	2.20
C	86.15	C_4H_{10}	0.28
H_2O	0.50	C_5H_{12}	0.02
N_2		C_6H_{14}	
O_2		CO_2	0.50
		O_2	
		N_2	1.95
TOTAL	100.00	TOTAL	100.00
B.T.U./lb.	18,600	B.T.U./cu. ft.	1022
		At 60°F, 30 in. Hg.	

Expected Performance is based on Comb. Air entering UNIT at 80°F., 60% rel. Humidity, 0.013 Lb. Moisture/Lb. Dry Air, 29.29 in. Hg. Barometric Press. conditions and equipment given on this summary sheet and arrangement shown on Dwg. No. V-3838-3 Rev.A

COL. 2 — EXPECTED PERFORMANCE

Steam-Actual-Continuous-M-lb./hr.	200.0	200.0	1
Type of Fuel	OIL	GAS	2
Burners - No. in use per unit	2	2	3
Excess air leaving BOILER %	15	10	4
FURN.LIB.M-BTU/HR/FT³	81.3	85.0	5
QUANTITIES M - LB./HR.			
Continuous Blowdown			6
Fuel (Gas - M SC FH)	12.7	241.2	7
Flue Gas Leaving BOILER	218.2	209.7	8
Air FOR COMBUSTION	205.5	198.9	9
PRESSURES LB./SQ. IN			
Min. at Feed Inlet	281	NOTE	10
Drop thr ECON+FWR+ Feed Valve	41	—	11
Min. Oper. at Boiler Drum	240	—	12
Drop from Drum to VALVE Outlet	15	—	13
Steam at VALVE Outlet	225	—	14
TEMPERATURES °F			
Steam	SATURATED	—	15
Flue Gas Leaving Boiler	587	592	16
" " " Economizer	375	378	17
" " " Air Heater			18
Water Entering ECONOMIZER	220	220	19
" Leaving Economizer	282	281	20
Air Entering UNIT	80	80	21
" Leaving Air Heater			22
DRAFT LOSS IN. OF WATER			
Boiler	8.6	7.9	23
Economizer	2.0	1.9	24
Air Heater			25
Flues	1.0	0.9	26
AIR RESIST. IN. OF WATER			
Burner and Windbox	8.0	7.5	27
Ducts	0.3	0.3	28
Air Measuring Device	2.0	1.9	29
XXXXXXXXXX SILENCER	0.6	0.6	30
Air Heater			31
TOTAL (Net.)	22.5	21.0	32
HEAT LOSSES %			
Dry Gas	6.06	5.30	33
Hydrogen and Moisture in Fuel	6.48	11.05	34
Moisture in Air	0.16	0.15	35
Radiation	0.40	0.40	36
Unacc. Loss and Mfrs. Margin	1.00	1.00	37
Total Heat Loss	14.10	17.90	38
EFFICIENCY	85.9	82.1	39
Max. Allow. Boiler Conc. P.P.M.	3500		40
SOLIDS in Steam P.P.M.	3		41

REVISIONS	No.	Description	By	Date	
					42
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					45

By J.A. Chk'd. RWH No. V-3838-3 Date Sept. 21/72 46

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COL. 1 — EQUIPMENT AND FUEL

UNI.
- No. of Units — Type
- Specific Designation
- Design Press. psig.

S.H.
- Type
- No. Gas Passes — No. Steam Passes

ECON.
- Type — No. Gas Passes
- Design Press. psig. — Make

AIR HEATER
- Type — Make
- No. Gas Passes — No. Air Passes — Thru Elements

BURNER
- Make — No./Furnace
- Type

HEATING SURFACE

	ABMA — Sq. Ft.	Full Cir. Sq. Ft.	Furnace Volume
BOILER			
FURNACE			
TOTAL			Cu. ft.

F.D. FAN
- Type
- Net — Lbs./Hr. at — "Wg and — °F.
- T.B. — Lbs./Hr. at — "Wg and — °F.

STAL.
- Height above — Ft. — Dia. at Top—In.
- Construction

DRIVES

Equipment	H.P.	R.P.M.	Type	Electrics

FUEL AS FIRED

LIQUID	GASEOUS
Fuel	Fuel
Analysis	Analysis
% by	% by
Ash	CH_4
S	C_2H_6
H_2	C_3H_8
C	C_4H_{10}
H_2O	C_5H_{12}
N_2	C_6H_{14}
O_2	CO_2
	O_2
	N_2
TOTAL	TOTAL
B.T.U./lb.	B.T.U./cu. ft.
	At 60°F, 30 in. Hg.

Expected Performance is based on Comb. Air entering UNIT at 80°F., 60% rel. Humidity, 0.013 Lb. Moisture/Lb. Dry Air, 29.29 in. Hg. Barometric Press. conditions and equipment given on this summary sheet and arrangement shown on Dwg. No. V-3838-3 Rev.A

COL. 2 — EXPECTED PERFORMANCE

	Steam-Actual-Continuous-M-lb./hr.	100.0	100.0	1
	Type of Fuel	OIL	GAS	2
	Burners - No. in use per unit	2	2	3
	Excess air leaving BOILER %	18	12	4
	FURN. LIB. M-BTU/Hr/FT³	40.0	41.9	5
QUANTITIES M - LB./HR.	Continuous Blowdown			6
	Fuel (Gas - M SC FH)	6.3	118.9	7
	Flue Gas Leaving boiler	110.2	105.1	8
	Air FOR COMBUSTION	103.9	99.8	9
PRESSURES LB./SQ. IN	Min. at Feed Inlet	281		10
	Drop thru Econ&FWR+ Feed Valve	52		11
	Min. Oper. at Boiler Drum	229		12
	Drop from Drum to VALVE Outlet	4		13
	Steam at VALVE Outlet	225		14
TEMPERATURES °F	Steam	SATURATED		15
	Flue Gas Leaving Boiler	492	495	16
	" " " Economizer	297	300	17
	" " " Air Heater			18
	Water Entering ECONOMIZER	220	220	19
	" Leaving Economizer	277	277	20
	Air Entering UNIT	80	80	21
	" Leaving Air Heater			22
DRAFT LOSS IN. OF WATER	Boiler	2.2	2.1	23
	Economizer	0.5	0.5	24
	Air Heater			25
	Flues	0.3	0.3	26
AIR RESIST. IN. OF WATER	Burner and Windbox	2.1	2.0	27
	Ducts	0.1	0.1	28
	Air Measuring Device	0.5	0.5	29
	~~XXXXXXXXXXXX~~ SILENCER	0.2	0.1	30
	Air Heater			31
	TOTAL (Net.)	5.9	5.6	32
HEAT LOSSES %	Dry Gas	4.68	4.04	33
	Hydrogen and Moisture in Fuel	6.30	10.75	34
	Moisture in Air	0.12	0.11	35
	Radiation	0.80	0.80	36
	Unacc. Loss and Mfrs. Margin	1.00	1.00	37
	Total Heat Loss	12.90	16.70	38
EFFICIENCY		87.1	83.3	39
Max. Allow. Boiler Conc. P.P.M.		3500		40
SOLIDS	In Steam P.P.M.	3		41

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					42
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By J.A Chk'd. RWH No. V-3838-3 Date Sept 21/72 46

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BLR #4.

The following, or equivalent, will be supplied for the unit:

One (1) Kentube extended surface economizer.

GENERAL DATA

Number Furnished:	One (1)
Design Pressure:	325 psig
Size of Inlet and Outlet Connections:	4"
Heating Surface:	6,138 sq. ft.

The economizer will include the following material:

(a) Headers

	Size	Thickness
Inlet & Outlet	6 5/8" ?	Schedule 80

(b) Mountings

	No.	Size	Description	Connection
Drain Valve	1	3/4"	Velan W-254B-2TY	Welded
Vent Valve	1	3/4"	Velan W-254B-2TY	Welded

(c) Tubes

Diameter	Material	Thickness
1-7/8"O.D.	SA-178 Grade A	0.095

(d) Fins

36 fins per foot of tube length

.060 thick x 3/4" high - carbon steel

(e) Casing

The economizer will be enclosed in a 10 gauge inner steel casing.

(f) Supports

Supporting steelwork will be supplied to support the economizer as shown on the Company"s Drawing V-3838-3 Rev.A The steelwork will be designed to the AISC Specification.

The steel will be ASTM A36 and cleaned and painted with one coat of shop primer suitable for finishing coat by Customer.

CHOL TO SUPPORT FROM STRUCTURE

F

Cleaver Brooks®
packaged watertube boilers

BLR # 5

Date: 10/12/82 By: WAB	EXPECTED PERFORMANCE SHEET	Date: _____ Approved: _____	
Burner: CN-7	Boiler Model DL 94	Customer: Central Heat Dist. Ltd.	
Superheater: - sqft	Blr.Des.Press: 260 psig		
Air Heater: -			
Economizer: 3607 sqft	Furn: Volume: 1654 cuft		
Alt. 5/ft. "Hg.corr.F -	H.S.: Boiler: 5418 sqft		
hst (Btu/lb) 1200.42	Proj.W.W.: 923 sqft	Proposal No. P- 82-09-1132A	
hw (Btu/lb) 219.01	Total: 6341 sqft	Contract No. WT-	
Δh (Btu/lb) 981.41			
Superheat: °F -			

			W/ECONO		W/ECONO	
1	Steam Flow, lbs/hr		75,000	75,000	75,000	75,000
2	Cont. Blowdown, lbs/hr		2,250	2,250	2,250	2,250
3	Rate %		100	100	100	100
4	Type Firing		NG	NG	Oil	Oil
5	EXCESS AIR (%)	In Furnace & Boiler	10	10	15	15
6		Leaving	-	-	-	-
7		Leaving	-	-	-	-
9	PRESS. PSIG	Steam at S.H. Outlet	-	-	-	-
10		Drop Drum to S.H. Outlet	-	-	-	-
11		Drum Operating	225	225	225	225
12		Drop thru Economizer	9	9	9	9
13	TEMPERATURES DEGREES F	Saturated Steam	397	397	397	397
13a		Flue Gas Lv. Furnace	1930	2004	1956	1979
14		Flue Gas Lv. Boiler	510	510	520	520
15		Flue Gas Lv. Econ.	330	-	340	-
16		Flue Gas Lv. A.H.	-	-	-	-
16a		Flue Gas Lv. A.H.	-	-	-	-
17		Water Enter. Econ.	250	-	250	-
18		Water Enter. Boiler	298	250	301	250
19		Air for Comb.	80	80	80	80
20		Air Enter. A.H.	-	-	-	-
21	Heat Output, x 1000 Btu/hr		73,949	73,949	73,949	73,949
21a	Heat Input, x 1000 Btu/hr		88,430	93,055	85,701	90,152
22	HEAT LOSSES PER CENT	Dry Gas	4.51	7.75	5.32	9.00
23		H_2 and H_2O in Fuel	10.73	11.51	6.70	7.18
24		Moisture in Air	0.12	0.21	0.14	0.24
25		Unburned Comb.	-	-	-	-
26		Radiation	0.56	0.56	0.56	0.56
27		Unaccounted For	0.50	0.50	1.00	1.00
28		Total Heat Loss	16.42	20.53	13.72	17.98
29	Efficiency of Unit, %		83.58	79.47	86.28	82.02
30	QUANTITIES Fuel Oil	18800 Btu/lb) lb/hr or	-	-	4559	4795
30a		Btu/gal) Gal/hr	-	-	-	-
31	Gas	Btu/SCF) SCFH or	-	-	-	-
31a		21100 Btu/lb) lb/hr	4193	4410	-	-
32		Flue Gas Lv. Furn.&Blr., lb/hr	75,557	79,464	78,906	83,003
34		Flue Gas to Stack, lb/hr	75,557	79,464	78,906	83,003
35		Air for Comb, lb/hr	71,364	75,054	74,347	78,208
36		Air to A.H, lb/hr	-	-	-	-
37		or Air for comb, SCF	16,158	16,993	16,833	17,707
38	FLUE GAS RESISTANCE W.G. In	Furnace & Boiler	5.50	6.08	6.00	6.63
40		Economizer	1.50	-	1.50	-
41		Air Heater	-	-	-	-
43		~~Ducts~~ Breeching	0.50	0.30	0.50	0.30
44		Pressure in Furnace	7.50	6.33	8.00	6.93
45	AIR RESIS. W.G. In	Burner & Windbox	10.25	11.34	11.12	12.31
46		Air Heater	-	-	-	
47		~~Ducts~~ Breeching	-	-	-	
48		Net Resistance	17.75	17.72	19.12	19.24
49	Furn. Ht.Rel., Btu/hr/cft		53,494	56,261	51,815	54,505
50	Furn. Ht.Rel., Btu/hr/sqft,proj.WW		95,861	100,818	92,851	97,673
51	Heat Abs. Rate, Btu/hr/sqft		11,083	11,662	11,057	11,662
52						
53						

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PERFORMANCE AND GUARANTEES

BLR #5

MODEL

The unit we are offering for your consideration is a Cleaver-Brooks Model DL94 designed to fire Natural gas or No. ~~6~~ 5 fuel oil. ?

PERFORMANCE

The unit will be designed for the following:

Capacity	75,000	lbs./hr.
Operating Pressure	225	psig
Feedwater Temperature	250	°F.
Air Temperature	80	°F.
Elevation	100	Ft.

GUARANTEES

Efficiency at above capacity is 79.47% when firing Nat.Gas. 82.03% when firing Fuel Oil

Steam moisture content is 1/20 of 1 % when firing at rated capacity.

FUEL

Fuel Oil Regulated pressure to boiler is 125 psig.
Natural Gas regulated pressure to boiler 112" W.C

HEATING SURFACE

The unit will have the following heating surface:

EFFECTIVE Boiler Heating Surface	5418	Sq. Ft. ?
*Water Wall Projected Surface	923	Sq. Ft.
Total Heating Surface	6341	Sq. Ft.
Furnace Volume	1654	Cu. Ft.

DESIGN PRESSURE

The unit will have a design pressure of 260 psig in accordance with A.S.M.E. Drums will actually be designed for 260 psig and tubes for 970 psig. Piping, valves, and fittings will be suitable for a design pressure of 240 psig.

SAFETY VALVE SETTING

The safety valves will be set at the following:

First valve open at	psig and close at	psig.	(CODE)
Second valve open at	psig and close at	psig.	

ELECTRICAL POWER

For fan drive: 240/3/60
For control circuit: 115/1/60
(Step-Down Transformer included)

*No finned surface is included. All surface is projected tube surface.